Lesson 8
Area of Review

Section Outline

- AoR requirements
- Mechanics of subsurface injection
- Components of injection pressure
- Fracturing and fracture gradient
- Endangerment
- AoR calculations
- Exercise: Graphical method
- Discussion: AoR issues

Attachment A

“Give the methods and, if appropriate, the calculations used to determine the size of the area of review (fixed radius or equation).

The area of review shall be a fixed radius of 1/4 mile from the well bore unless the use of an equation is approved in advance by the Director.”

AoR Requirements

- Attachment A: AoR Methods
  - Calculations to determine size of AoR
  - ¼ mile unless calculation approved
- Attachment B: Maps of AoR
  - Location of all wells, faults, and surface features (in public record)

AoR Requirements

40 CFR 144.55

- Construction details for all wells in AoR that penetrate the injection zone

40 CFR 146.14(a)(3)

- Description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require.

Class I requirements

- The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, and drinking water wells located within one quarter mile of the facility property boundary. Only information of public record …

Class II and III Requirements

- II: In addition to the requirements for Class I, the applicant must include pertinent information known to the applicant. This requirement does not apply to existing Class II wells
- III: In addition to requirements for Class I, the applicant must include public water systems and pertinent information known to the applicant.

Radius of the AoR

- 40 CFR 146.6:
- AoR determined by either:
  – Fixed radius not less than ¼ mile
  – Zone of Endangering Influence (ZEI)

Components of Injection Pressure

- Existing lithostatic and hydrostatic pressure
- Darcy friction losses
- Displacement resistance

Fluid Injection

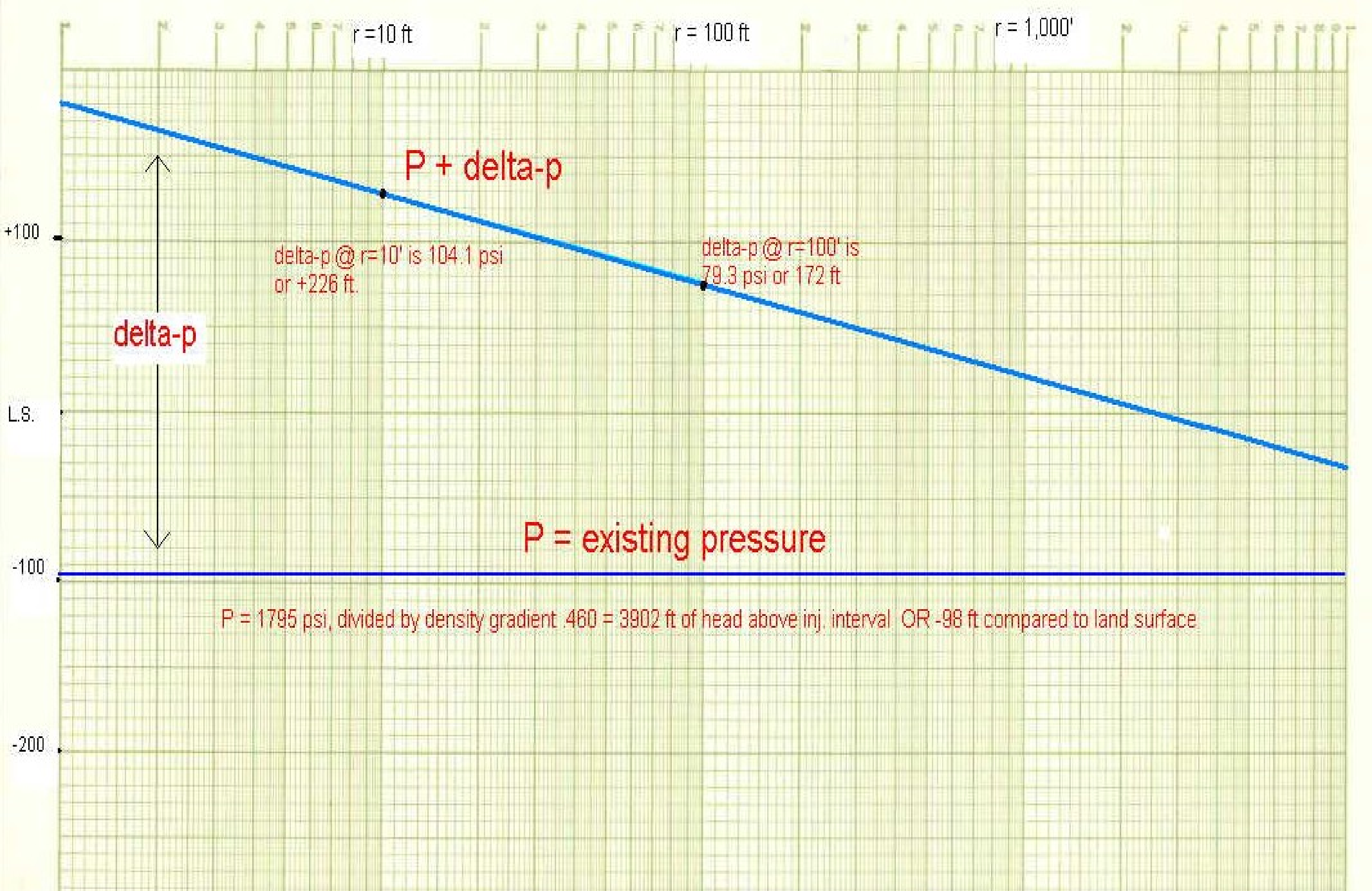
- Fluid is injected into saturated pores
  - Native water is displaced
  - or
  - Native water is compressed and system expands
- Injection reservoirs should be infinite-acting systems

Delta p (Δ p)

- Matthews and Russell (1967) show that pressure increase is greatest at the well, but decreases dramatically (log) with distance

$$\Delta p = 162.6 \frac{Q \mu}{k b} \left[\log \frac{k t}{\Phi \mu C r^2} - 3.23 \right]$$

Δp and Semi-Log Plot



Analysis of Formations

- Formation pressure eventually equalizes when injection stops and pressure dissipates
- Pressure buildup and equalization are unique in each formation, allowing for analysis of formation properties

Bottom Hole Pressure

- Bottom-hole pressure during injection (BHPI) consists of
  - Δ p (injection pressure at some Q) plus
  - Weight of the fluid column
    - Height of fluid x density, e.g.,

      4000 ft @ .4416 psi/ft = 1766 psi
- BHPI also expressed as gradient (psi/ft)
    - E.g., 1940 psi ÷ 4000 ft. = 485 psi/ft

Fracture Gradient

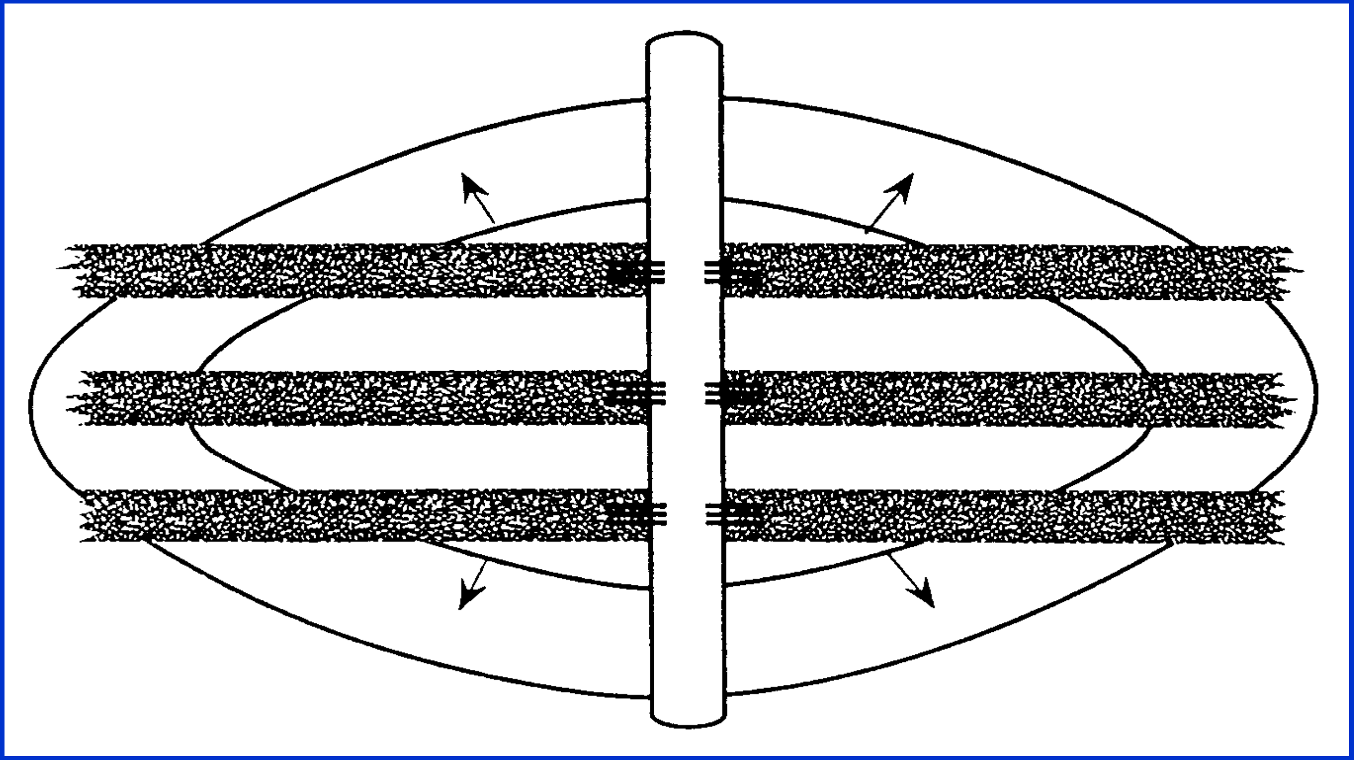
- Injection pressure can not exceed the fracture pressure
  - Of the injection zone (Class I), or
  - Of the confining zone (Class II)
- Fracture pressure is unique for every formation and time

Fracture Pressure

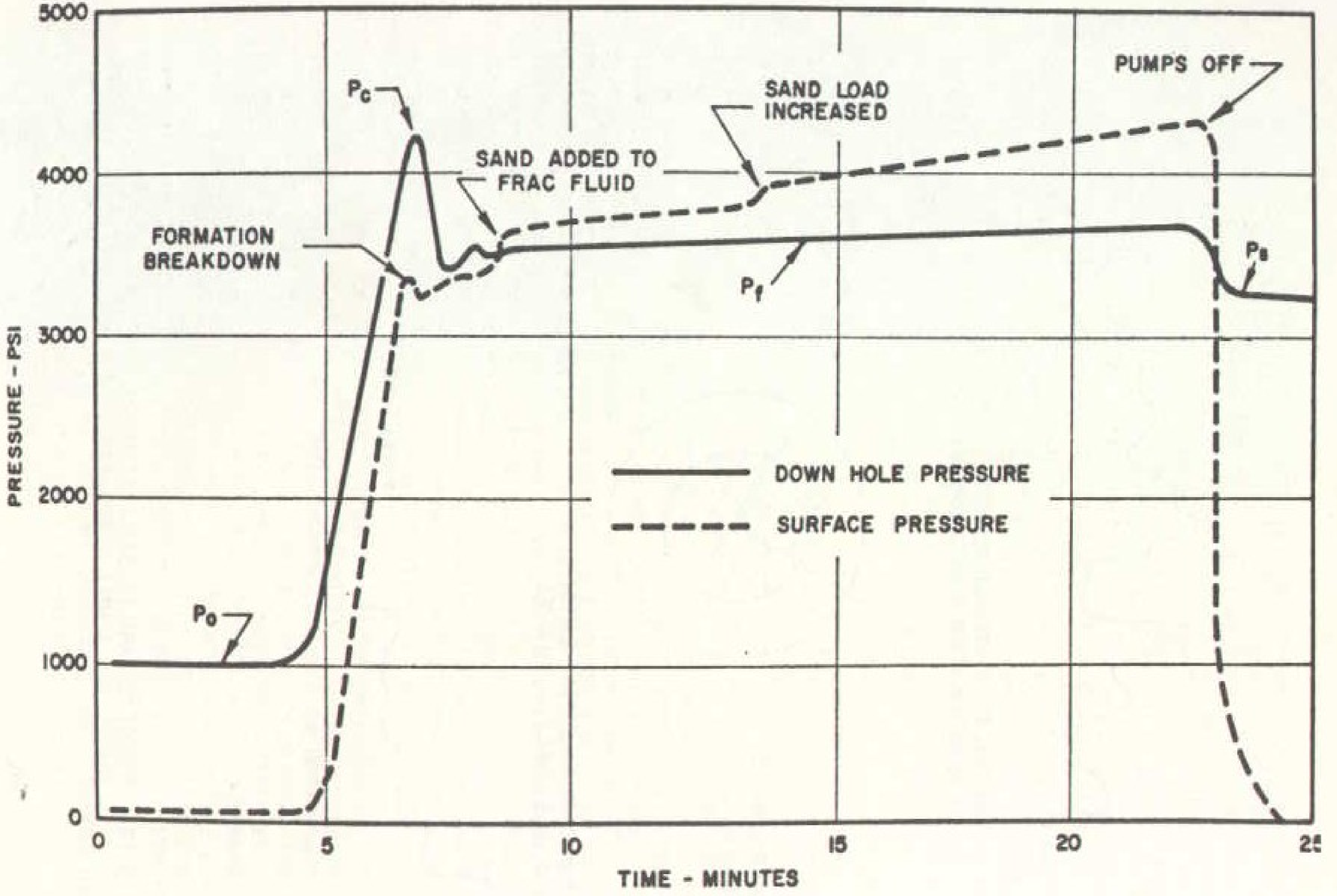
- Finding fracture pressure
  - Published data (oil and gas industry)
  - Measured downhole using injection test
  - Estimated

Hydraulic Fractures

- Planar, two lobes centered on wellbore

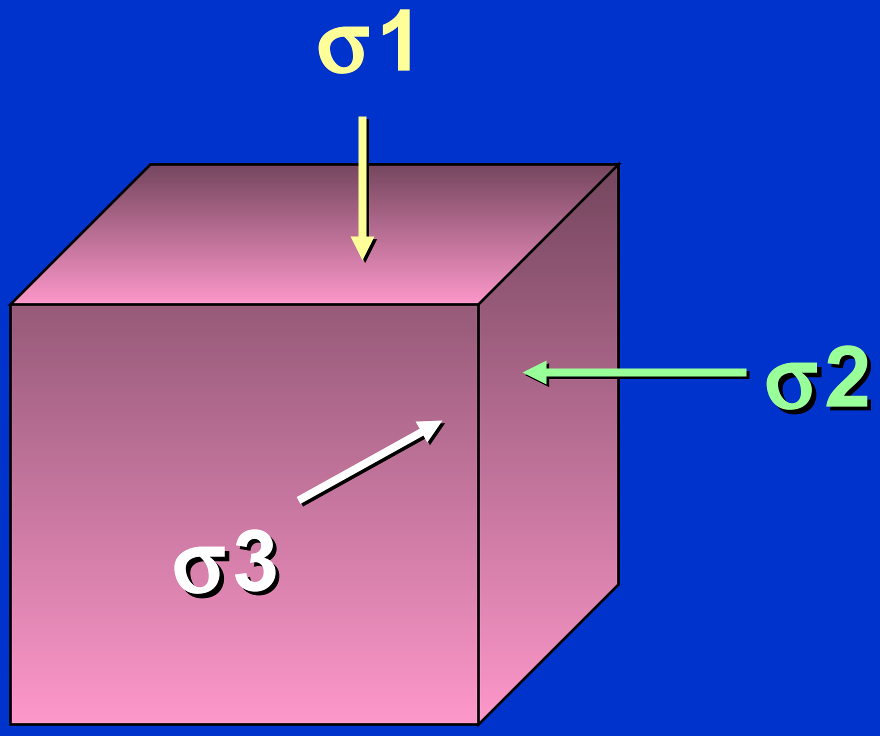


Step Testing and Frac Logs



Estimating Fracture Gradient

- Vertical stress
- Least and most horizontal stresses



$\sigma 1 > \sigma 3 > \sigma 2$

Hubbert and Willis (1972)

- Fracture orientation perpendicular to least principal stress
- Fracture gradient is usually from 0.64 to 0.73 psi/ft in typical oil sands
- More for shale-rich, hard rock, or thrust areas (up to 1.0 psi/ft)

Area of Review Calculations

- Endangerment
  - Pressure increase has the potential to cause a column of formation fluid in a conduit to extend above the level of the base of a USDW
- Suggested method in 40 CFR 146.6

40 CFR 146.6

$$r = \left(\frac{2.25\ KHt}{S10^x}\right)^{1/2}$$

where

$$X = \frac{4\pi KH\ (h_w - h_{bo} \times S_p G_b)}{2.3Q}$$

Area of Review Calculations

- $\Delta p = 162.6 \dfrac{Q\,\mu}{k\,b} \left[\log \dfrac{k\,t}{\Phi\,\mu C r^2} - 3.23 \right]$

- Δp declines logarithmically with distance; straight line on semi-log plot

Example: Injection Pressure

- Well depth: 4000 feet
- Thickness of interval (b): 50 feet
- Porosity (Φ): 30 percent
- Permeability (k): 400 md
- Injection rate (Q) = 1700 bbl/day
- Viscosity (μ) = 0.90 centipoise
- Duration of injection (t) =10 yr=87,600 hours
- Effective well radius (r) = .292 ft
- System compressibility(C) = 6.5×10^{-6} psi^{-1}
- Well tubing = 2.375”
- Injectate specific gravity = 1.02

Example: Injection Pressure

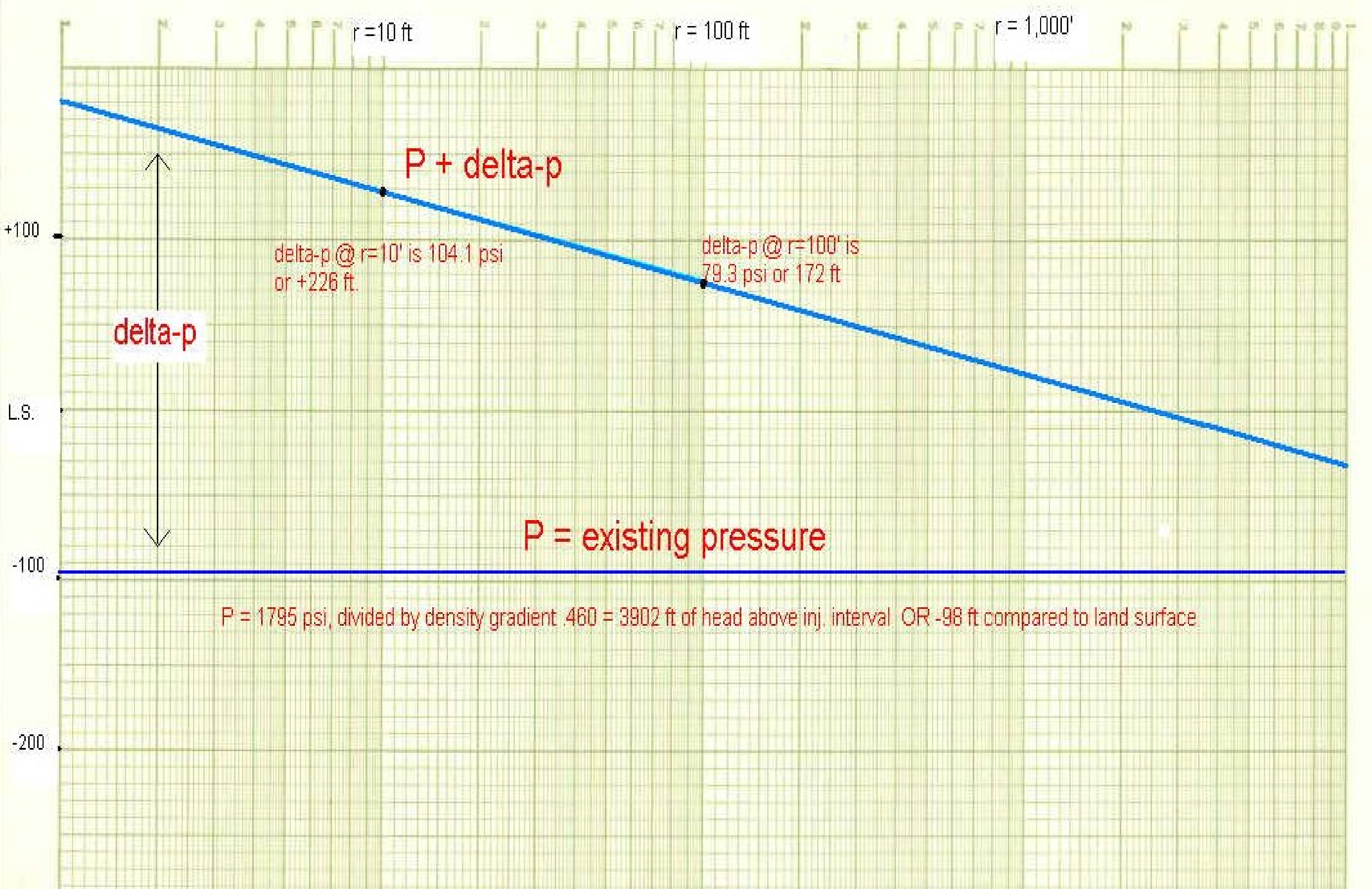
$$\Delta p = \frac{(162.6)\ (1700)\ (.90)}{(400)\ (50)} \quad x$$

$$\left[\ \log \frac{(400)\ (87600)}{(.30)\ (.90)\ (.0000065)\ (.292)^2} \ - \ 3.23\ \right]$$

Δ p = 138.6 psi at the injection face (10 yrs)

= 142.3 psi (20 years = 175,200 hours)

Δp and Semi-Log Plot



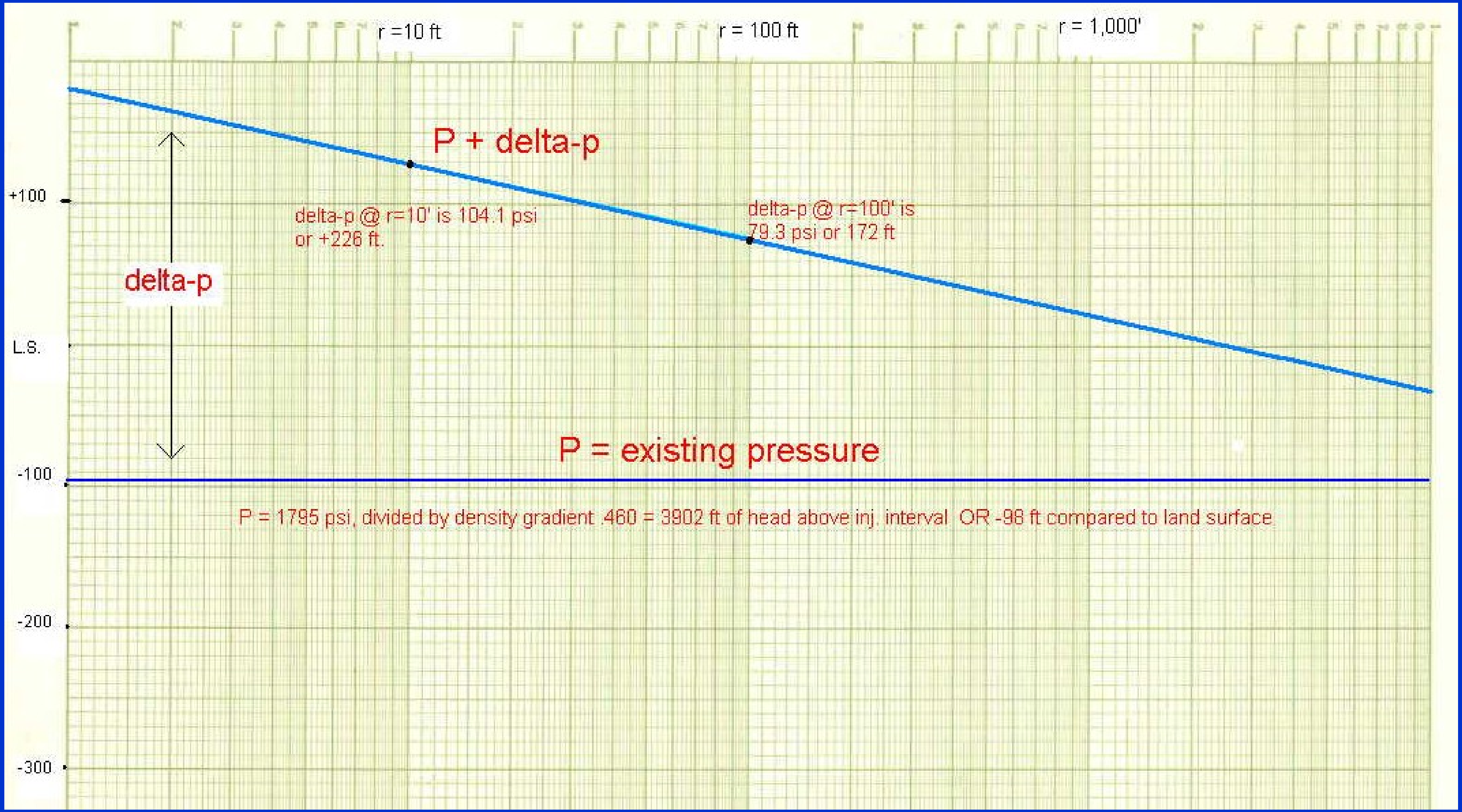
Analyzing the Zone of Endangerment

- Analysis needs to account for three elements
  - Changes in formation properties with distance
  - Differences in water density
  - Downward pressure from the USDW

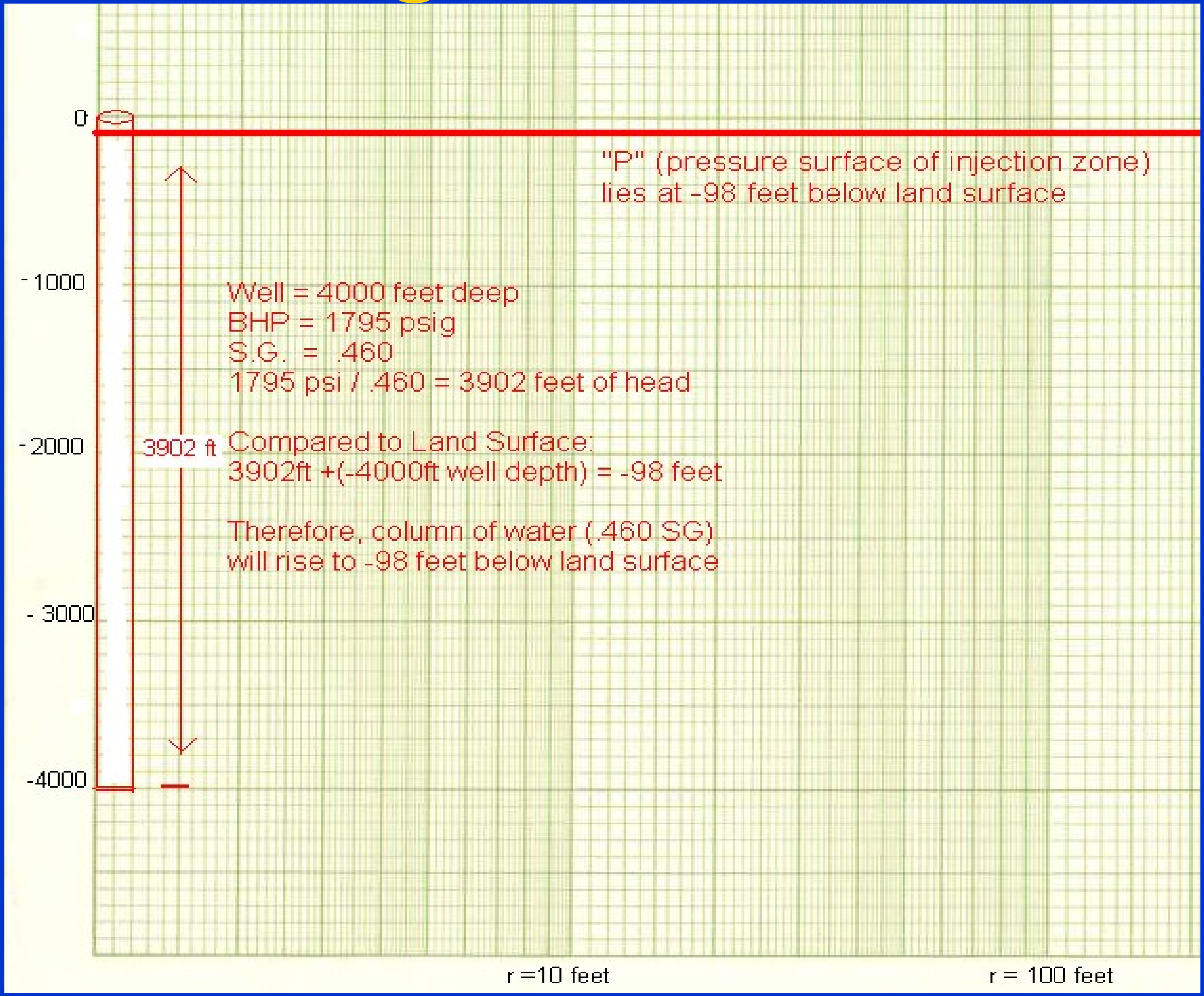
Graphical Method

- Step 1: Plot “cone of impression” in space
- Solve Δ p for two “r” values Add Δp to existing formation pressure
  - (A) Convert “psi” to “feet of head” using gradient
  - (B) Add “feet of head” to (-) depth, and plot on semi-log graph

Example Graph



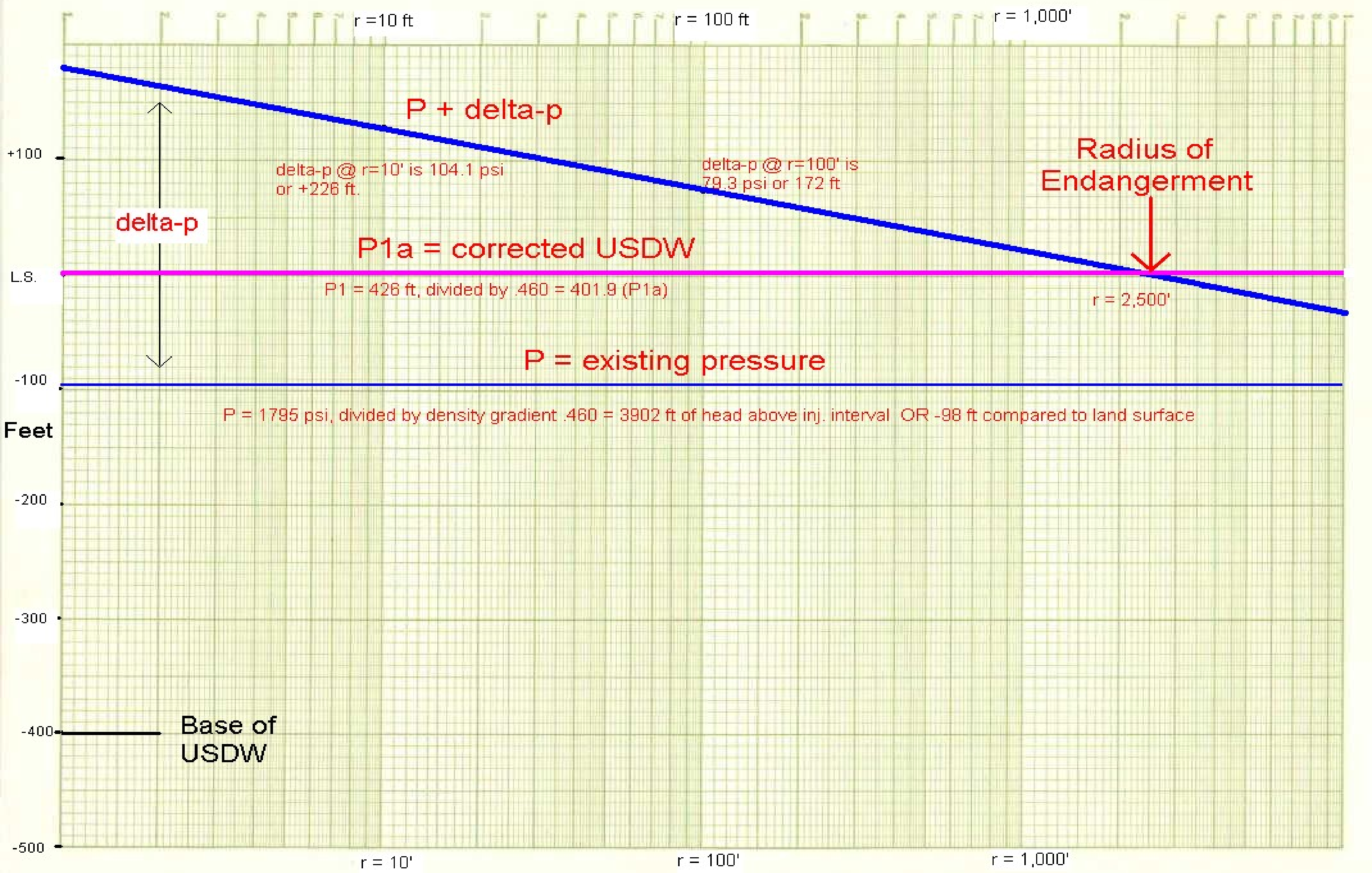
Calculating Pressure Surfaces



Graphical Method

- Step 2: Compare P + Δ p to P1a, the density-adjusted pressure surface of the USDW
  - (A) Calculate the height of the USDW water column (P1)
  - (B) Adjust density (USDW / formation gradient)
  - (C) Add to (-) depth of USDW base and plot
- Intersection is radius of endangerment

Completed Graph



Short Method

- Use as a check for ¼-mile radius

1) BHP+Δp (@1320ft.) \ density gradient
   - 1795+51 / .460 = 4014 feet of head
2) Subtract (well depth – depth to USDW)
   - 4014 – (4000 – 400) = 414 feet of head @usdw
3) USDW saturated thickness x density ratio
   - 400 feet x .433/.460 = 377 feet of head @usdw
4) Compare 2 and 3
   - If 2>3, ¼-mile AoR radius too small
   - If 2<3, AoR OK
   - 414>377: 1/4–mile AoR not enough

AoR Issues

- Some States use “mud gradient” calculations
  - Piston-displacement of .8 psi/ft mud column
  - Grossly understates radius of endangerment
- Most oil wells and Class II wells feature minimum long-string cement, and short surface casing
  - If injection interval offset, pathway to USDW

Review Essentials: Radius

- Well class requirements
  - Class 2: 1/4 mile or area permit
  - Class III: area permit?
  - Class I: 2 to 2.5 miles+
- Endangerment?
  - Class II in existing project: 1/4 mile
  - New Class II D project: short method
  - Class I or IID-commercial: full analysis

Review Essentials

- List of wells
  - Public information versus search
- Construction and cementing data
- Corrective action in later section

Lesson 9
Maps of Well and Area of Review

Purpose of Attachment B

- Visual depiction of potential migration conduits
- Identify other operations and land uses that may affect or be affected by the UIC facility

Information in the AOR

- Producing, injection and abandoned wells
- Dry holes
- Surface water bodies
- Mines and quarries
- Residences and roads
- Known or suspected faults

Frequent Omissions

- Map doesn’t extend one mile from property boundaries of the source
- Facility features are out of date
- Locations of drinking water supplies not consistent with PWSS program records
- Map scale is not meaningful

Administrative Record

- Comments issued to and responses received from applicant
- Ensure any map updates are inserted into the application to replace prior versions with omissions or errors

Lesson 10
Corrective Action Plan
and
Well Data

Purpose of Requirement

- Integrity of UIC system is dependent on proper containment
- Wells needing CA are likely vertical migration conduits, causing contamination
- Must identify conduits and ensure proposed measures are adequate to protect USDWs

Evaluation of Wells in AOR

- Well types to be reviewed
  - Active production
  - Other active injection
  - Temporarily abandoned
  - Permanently abandoned

What is the Requirement?

- UIC regulations require three steps
  - Identification of certain wells in AOR
  - Determining which of the wells need corrective action
  - Developing and submitting a plan for the action

CA Plan Evaluation

- What is being injected and how much
- Native fluids and injection by-products
- Potentially affected population
- Geology and hydrology
- Injection history
- P&A records and procedures
- Hydraulic connections with USDWs

Sources of Information

- Historic maps and aerial photographs
- Oil, gas and water well drilling records
- Well logs and completion records
- P&A permits and records
- Field survey for problematic wells
- GIS coverage

Corrective Action Options for Operations

- Reduce Δp (details in Lesson 14)
- Monitoring
- Remedial cementing
- Plugging or re-plugging

Corrective Action Options for Existing Wells

- Monitoring in the injection interval
- Remedial cementing
- Plugging offset wells

When is the USDW Protected?

- Site specific
- May require combination of responses
- EPA is responsible for determining protection is adequate
- Evaluate all options - what are success measures?
- Track the progress and complete implementation of the required actions!

Lesson 11 Construction, Cementing, and Cement Calculations

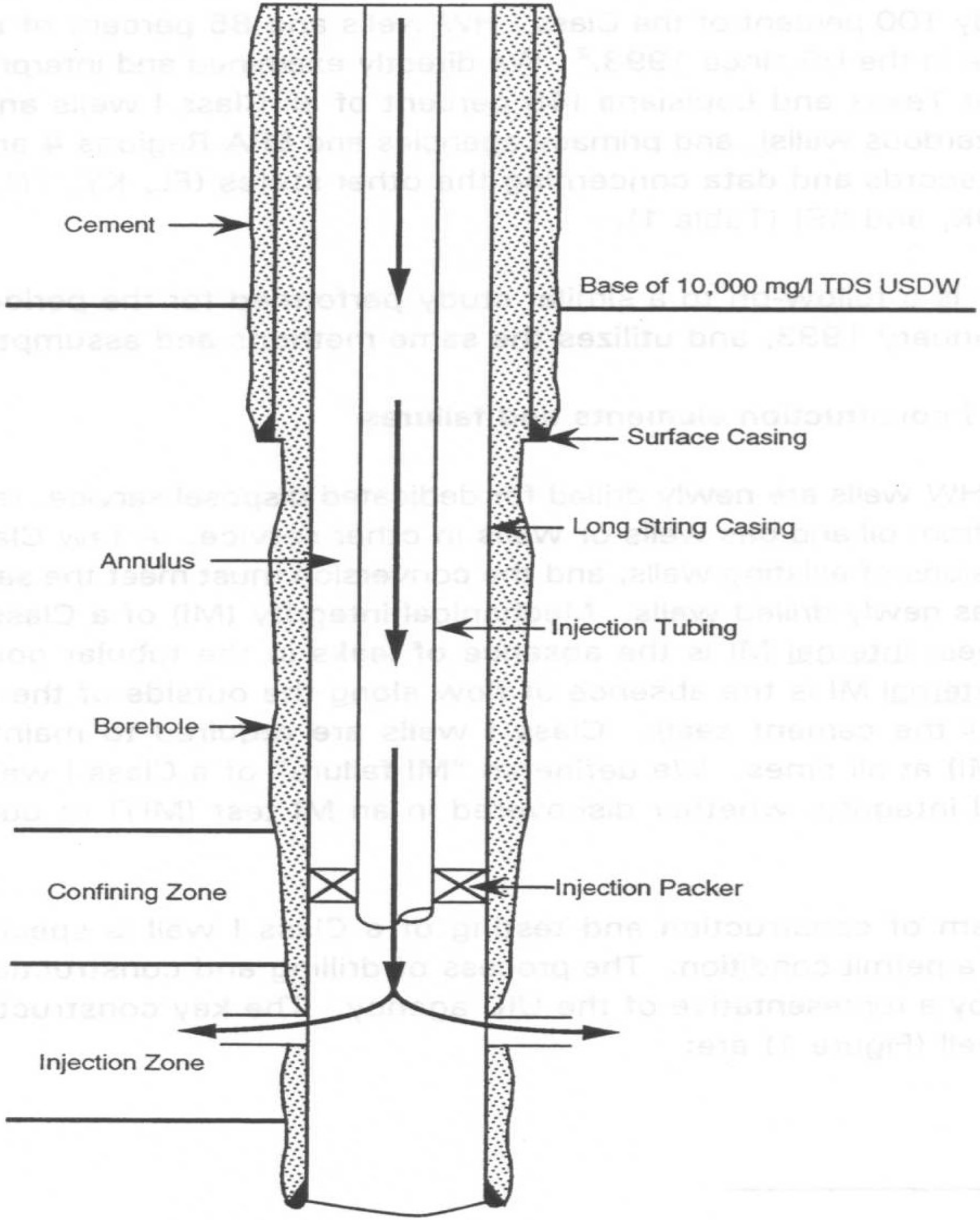
Attachments L and M

- Attachment L: Construction procedures
- Attachment M: Construction details

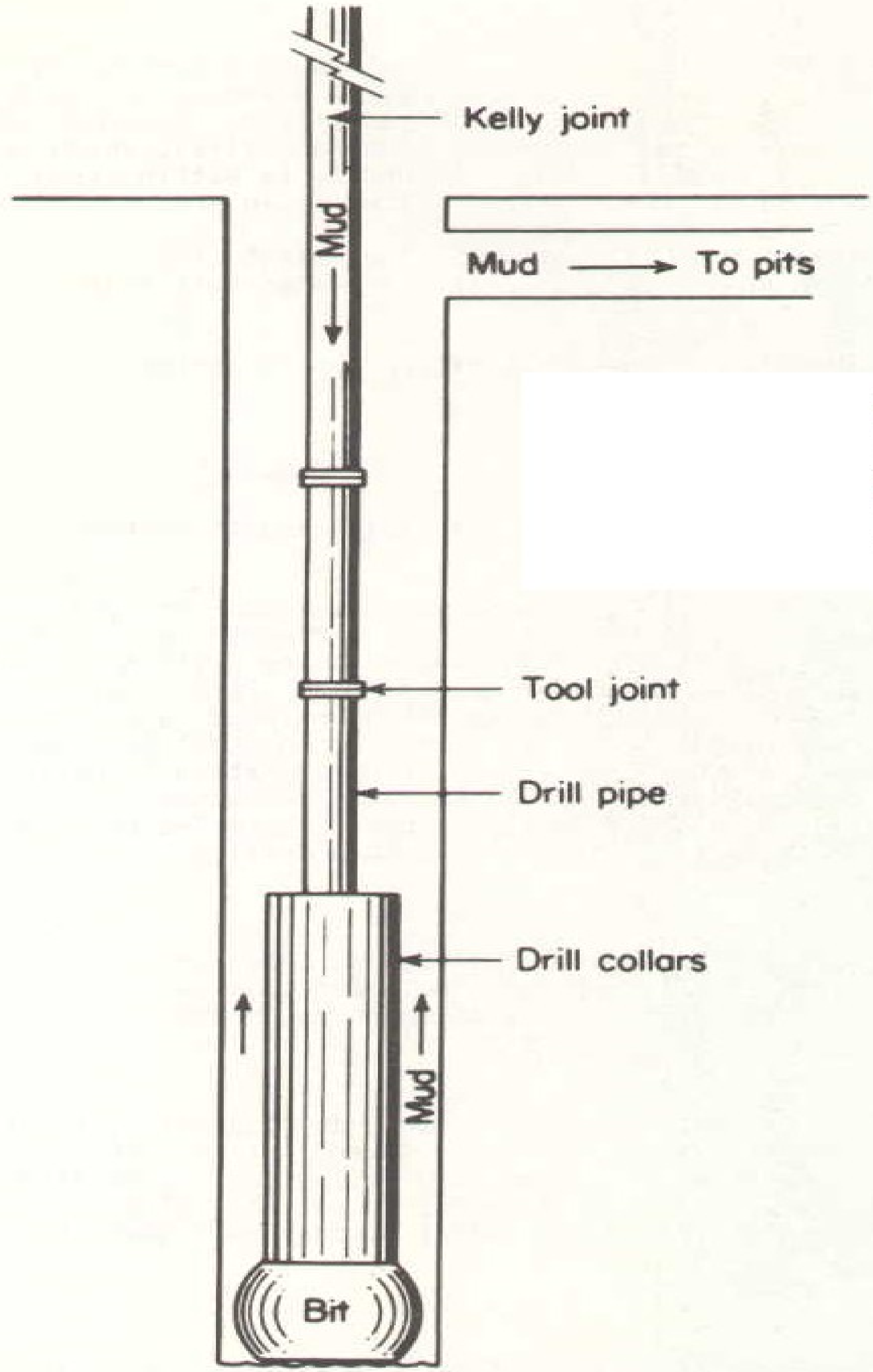
Performance Standard

All Class I, II, or III injection wells shall be cased and cemented to prevent movement of fluids ***into or between*** underground sources of drinking water.

Injection Well Components



Drilling



Kelly joint
Mud
Mud
To pits
Tool joint
Drill pipe
Drill collars
Mud
Bit

Drilling Hazards

- Environmental problems associated with construction
  - Deviation
  - Lost circulation
  - Junked hole or stuck pipe

Data Obtained During Drilling and Completion

- Numerous opportunities to obtain site-specific data
- Data used to predict performance
- Test types
  - Rock and fluid sampling
  - Geophysical logging
  - Pressure and transient testing

§146.12 “Considered…”

- Resistivity, SP, gamma, caliper logs
- Cement bond, temperature, or density log
- Fracture finder logs
- Fluid pressure, temperature, fracture pressure
- Physical and chemical characteristics of the injection matrix and formation fluids

Open-Hole Well Logs - Electrical

Method	Property	Application
Spontaneous potential (SP)	Electrochemical and electrokinetic potentials	Formation water resistivity (Rw); shales and nonshales; bed thickness; shaliness
Nonfocused electric log	Resistivity	1. Water and gas/oil saturation 2. Porosity of water zones 3. Rw in zones of known porosity 4. True resistivity of formation (Rw) 5. Resistivity of invaded zone
Focused conductivity log	Resistivity	1-4; very good for estimating R† in fresh water or oil base mud
Focused resistivity logs	Resistivity	• 1-4; especially good in determining R† of thin beds • Depth of invasion
Focused and nonfocused microresistivity logs	Resistivity	• Resistivity of the flushed zone (Rxo) for calculating porosity • Bed thickness

Open-Hole Well Logs – Elastic Wave Propagation

Method	Property	Application
• Transmission	• Compressional and shear wave velocities • Compressional and wave attenuations	• Porosity; lithology; elastic properties, bulk and pore compressibilities • Location of fractures; cement bond quality
• Reflection	• Amplitude of reflected waves	• Location of vugs, fractures; orientation of fractures and bed boundaries; casing inspection

Open-Hole Well Logs - Radiation

Method	Property	Application
Gamma ray	Natural radioactivity	Shales and nonshales; shaliness
Spectral gamma ray	Natural radioactivity	Lithologic identification
Gamma-Gamma	Bulk density	Porosity, lithology
Neutron-Gamma	Hydrogen content	Porosity
Neutron-Thermal Neutron	Hydrogen content	Porosity; gas from liquid
Neutron-Epithermal Neutron	Hydrogen content	Porosity; gas from liquid
Pulsed neutron capture	Decay rate of thermal neutrons	Water and gas/oil saturations; reevaluations of old wells
Spectral neutron	Induced gamma ray spectra	Location of hydrocarbons; lithology

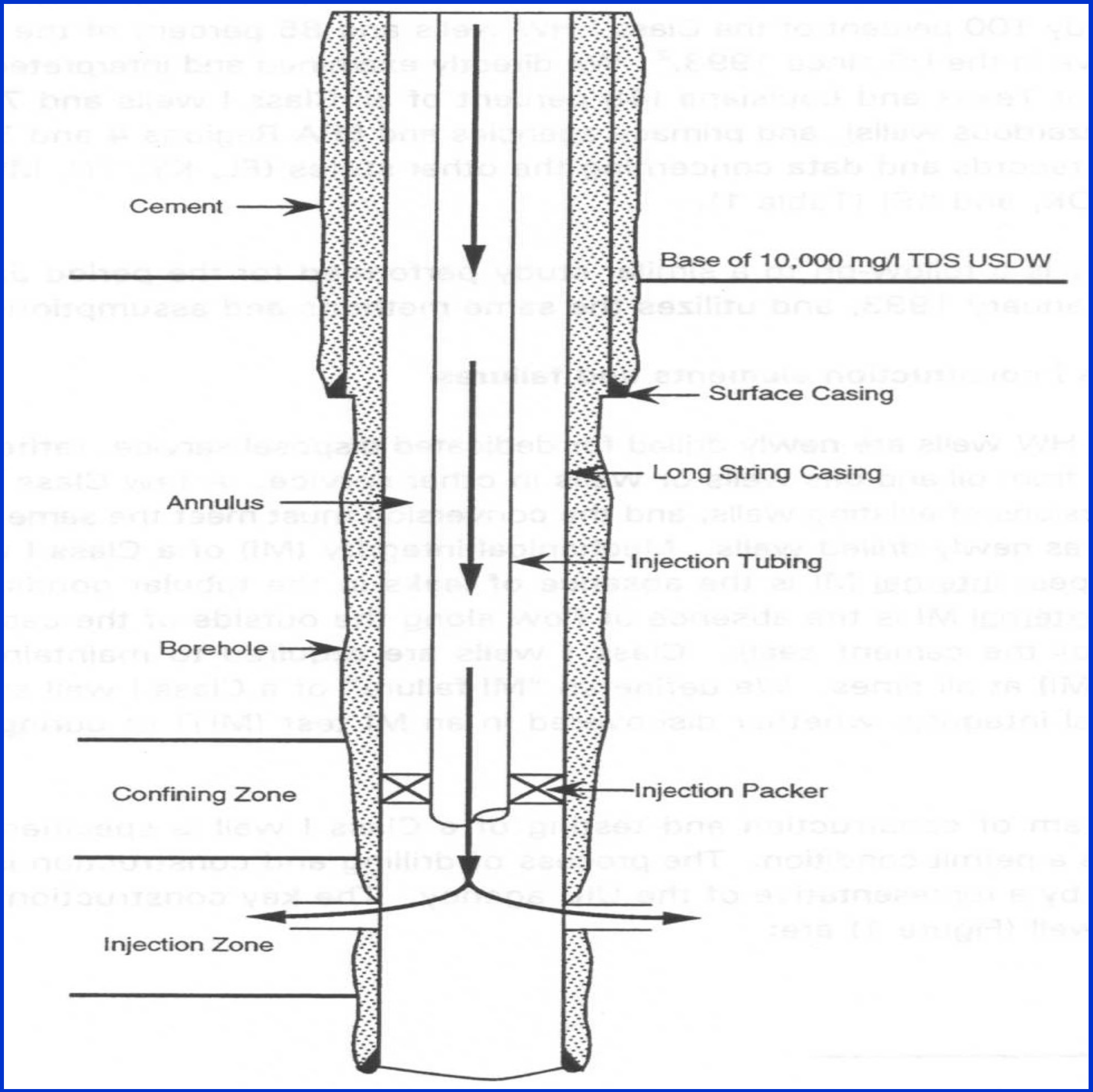
Open-Hole Well Logs - Other

Method	Property	Application
Gravity meter	Density	Formation density
Ultra-long spaced electric log	Resistivity	Salt flank location
Nuclear magnetism	Amount of free hydrogen; relaxation rate of hydrogen	Effective porosity and permeability of sands; porosity for carbonates
Temperature log	Temperature	Formation temperature

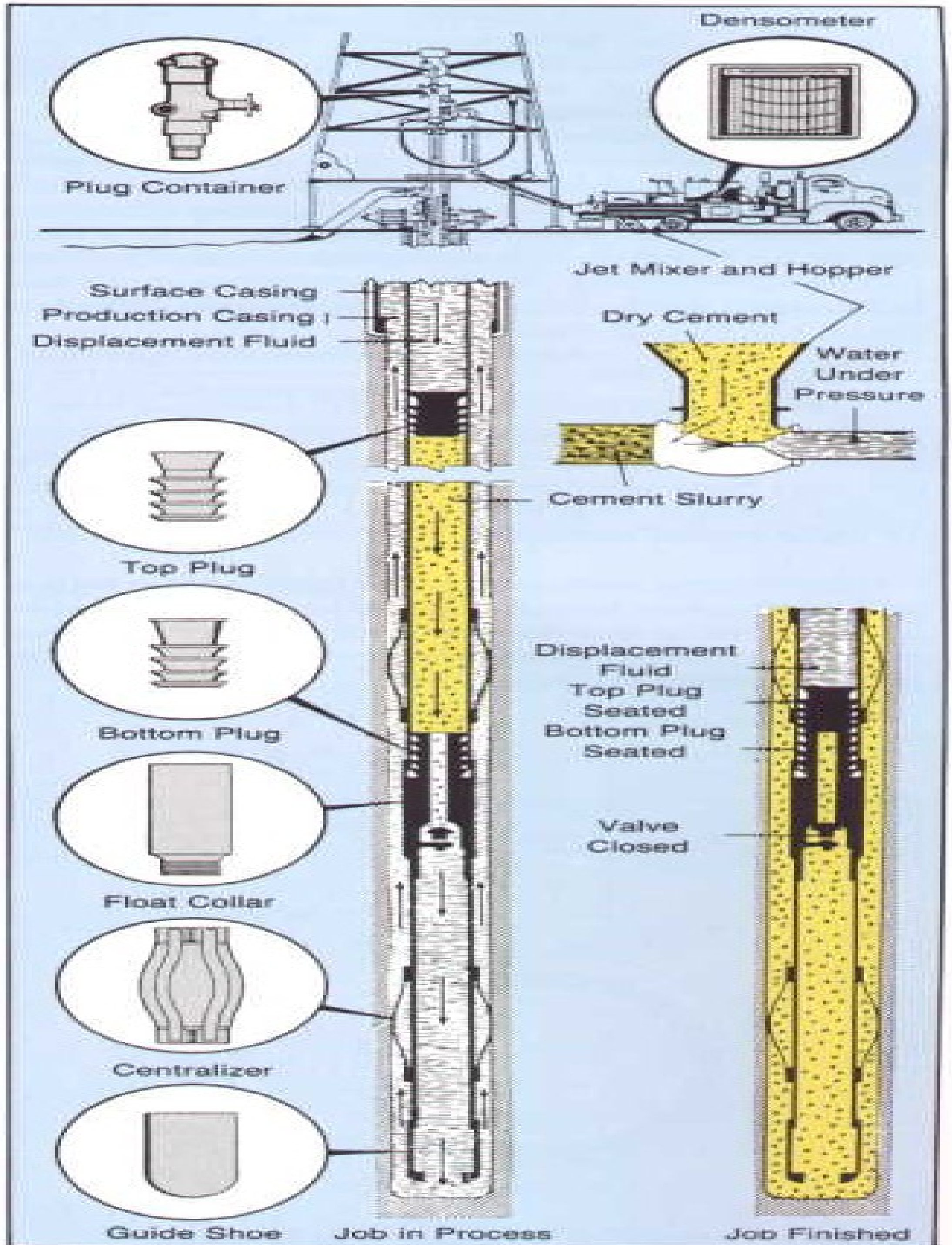
Cased Hole Logs

Log	Function
Cement bond	Determine extent and effectiveness of casing cementing
Gamma ray	Determine lithology and presence of radioactive tracers through casing
Neutron	Determine lithology and porosity through casing
Borehole televiewer	Provide an image of casing wall or well bore
Casing inspection	Locate corrosion or other casing damage
Flow meter	Locate zones of fluid entry or discharge and measure contribution of each zone to total injection or production
High resolution thermometer	Locate zones of fluid entry including zones behind casing
Radioactive tracer	Determine travel paths of injected fluids including behind casing
Fluid sampler	Recover a sample of well bore fluids
Casing collar	Locate casing collars for accurate reference
Fluid pressure	Determine fluid pressure in borehole at any depth
Casing caliper	Locate casing damage

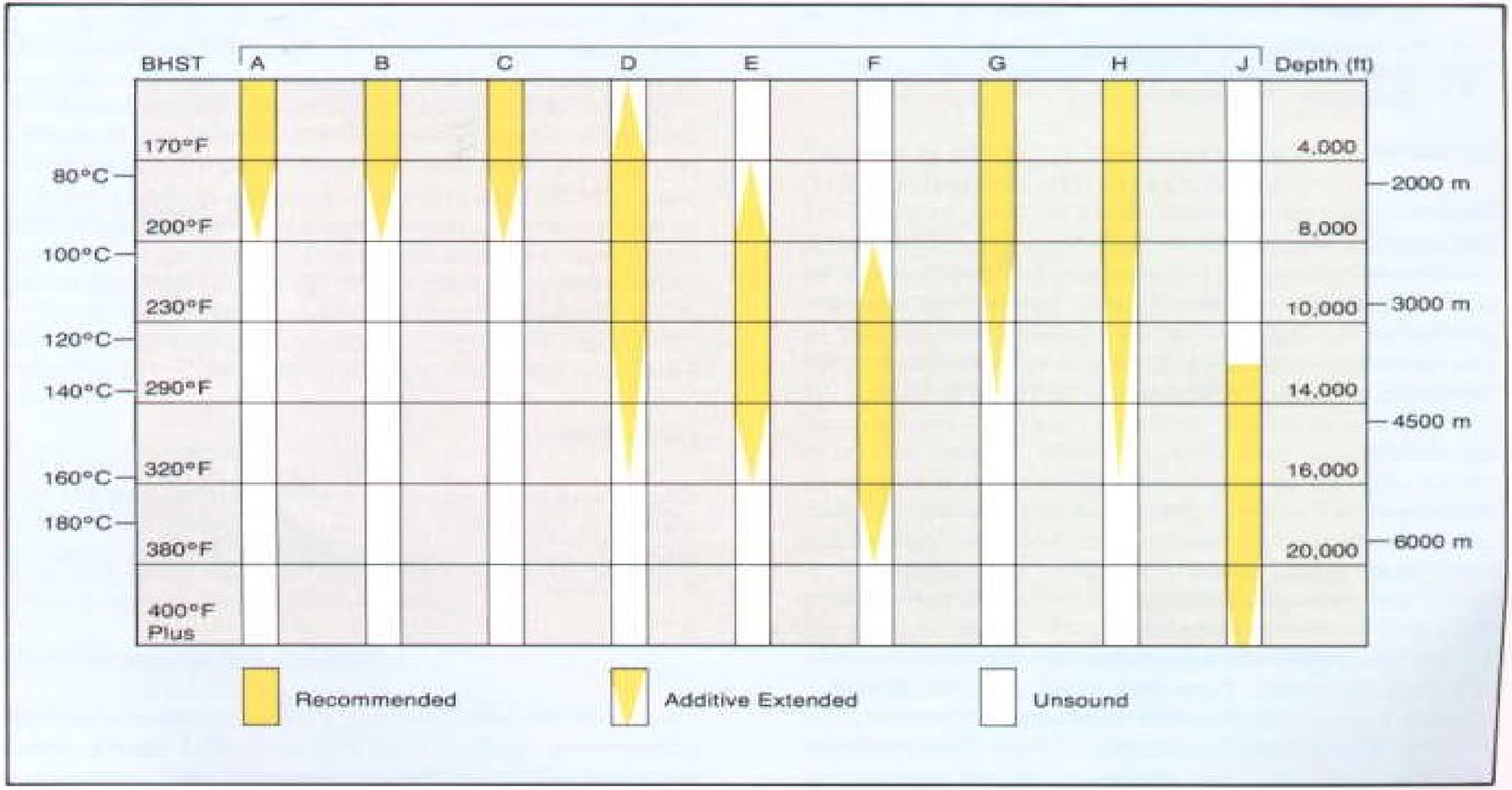
Cement and Cementing



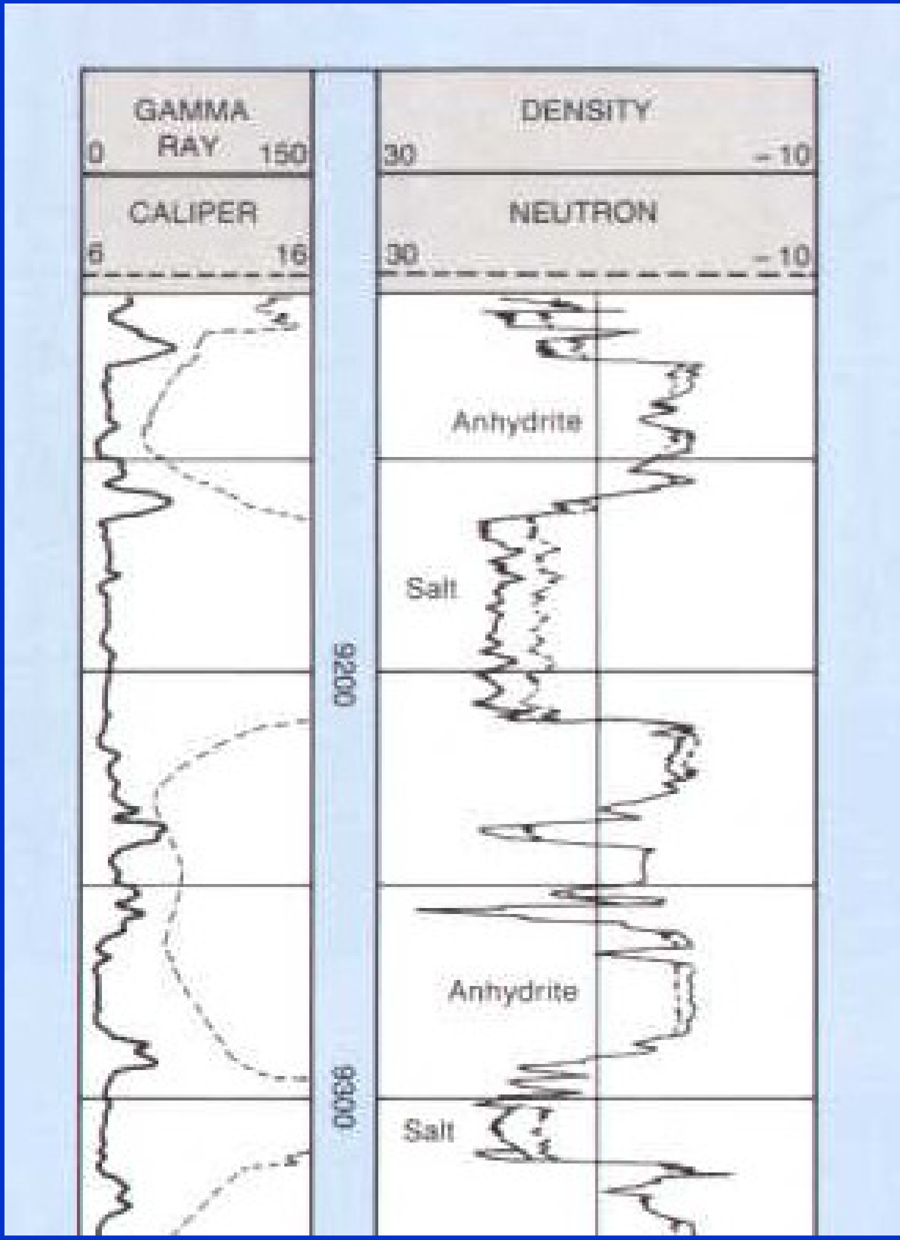
Cementing Overview



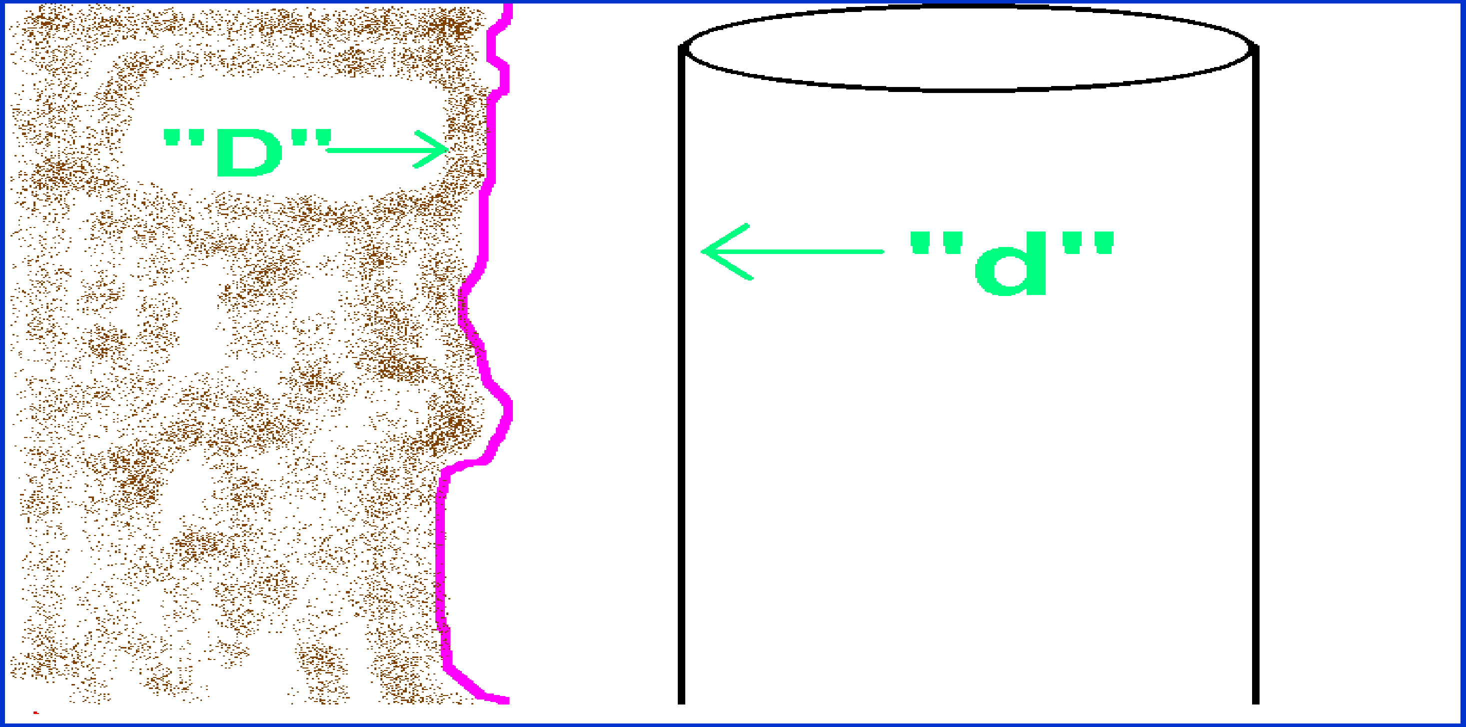
Cement Classes and Additives



Cement Volume Calculations

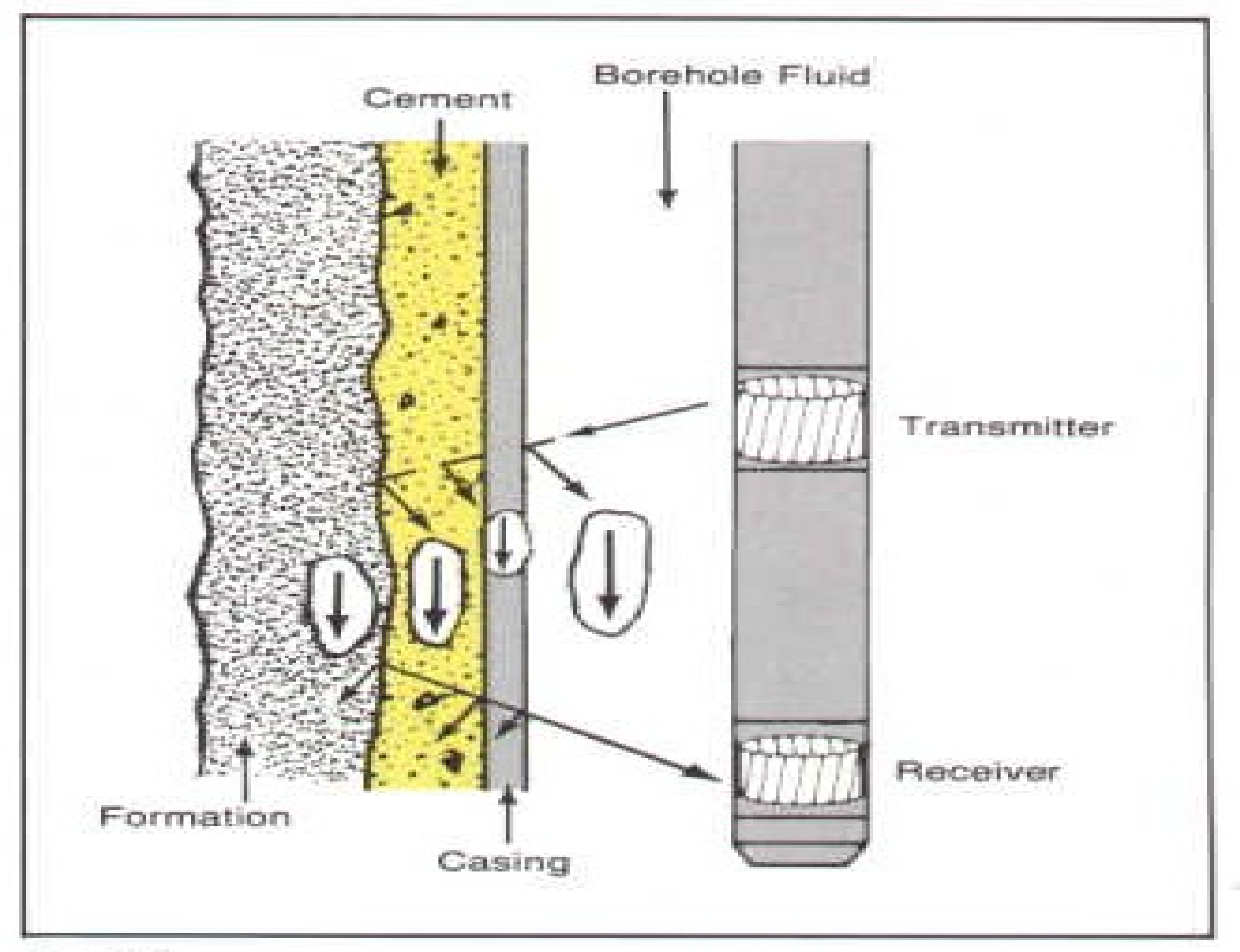


Cement Calculations

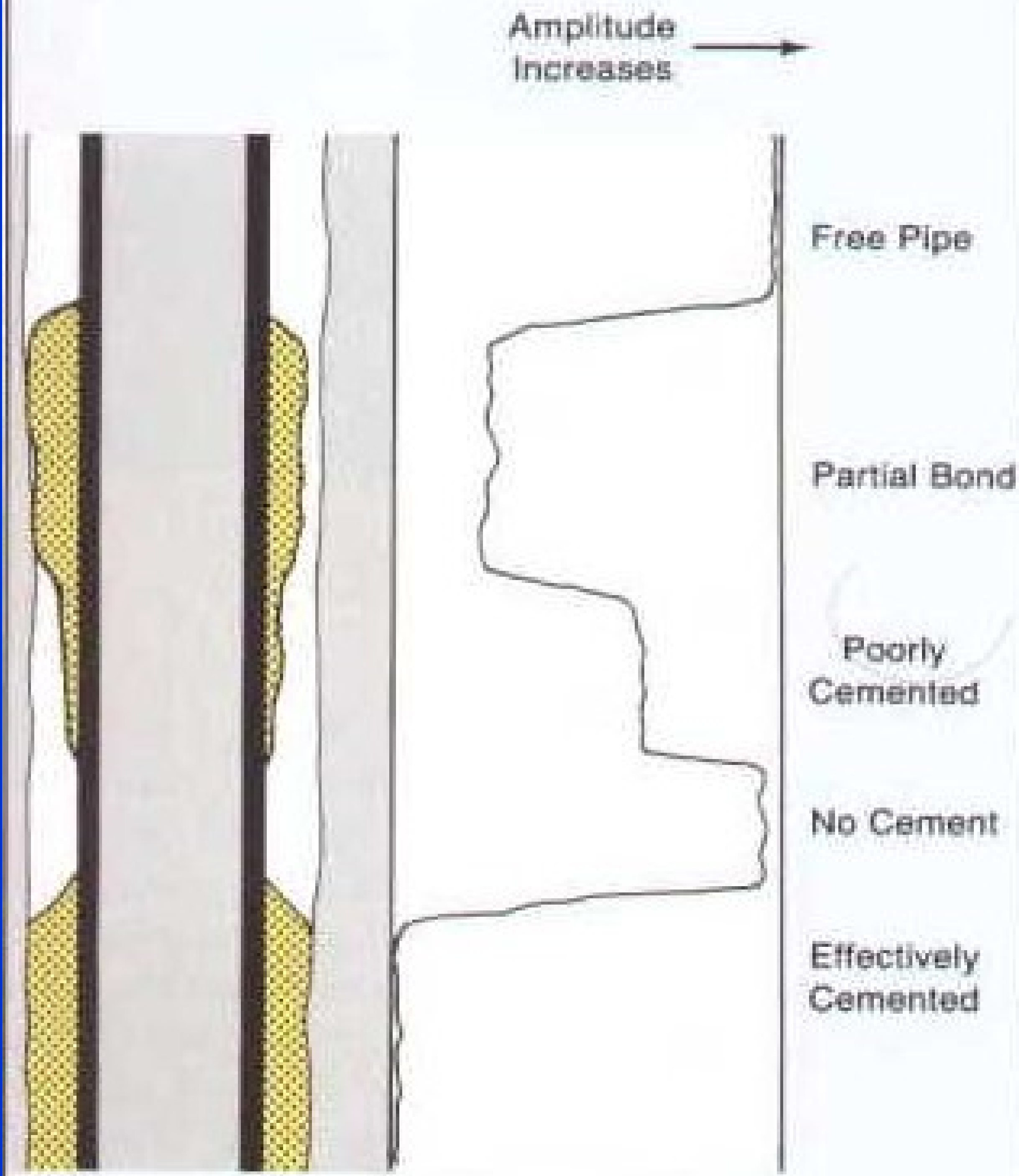


$$(D^2 - d^2)\ \ 0.0009714 = \text{bbl/foot}$$

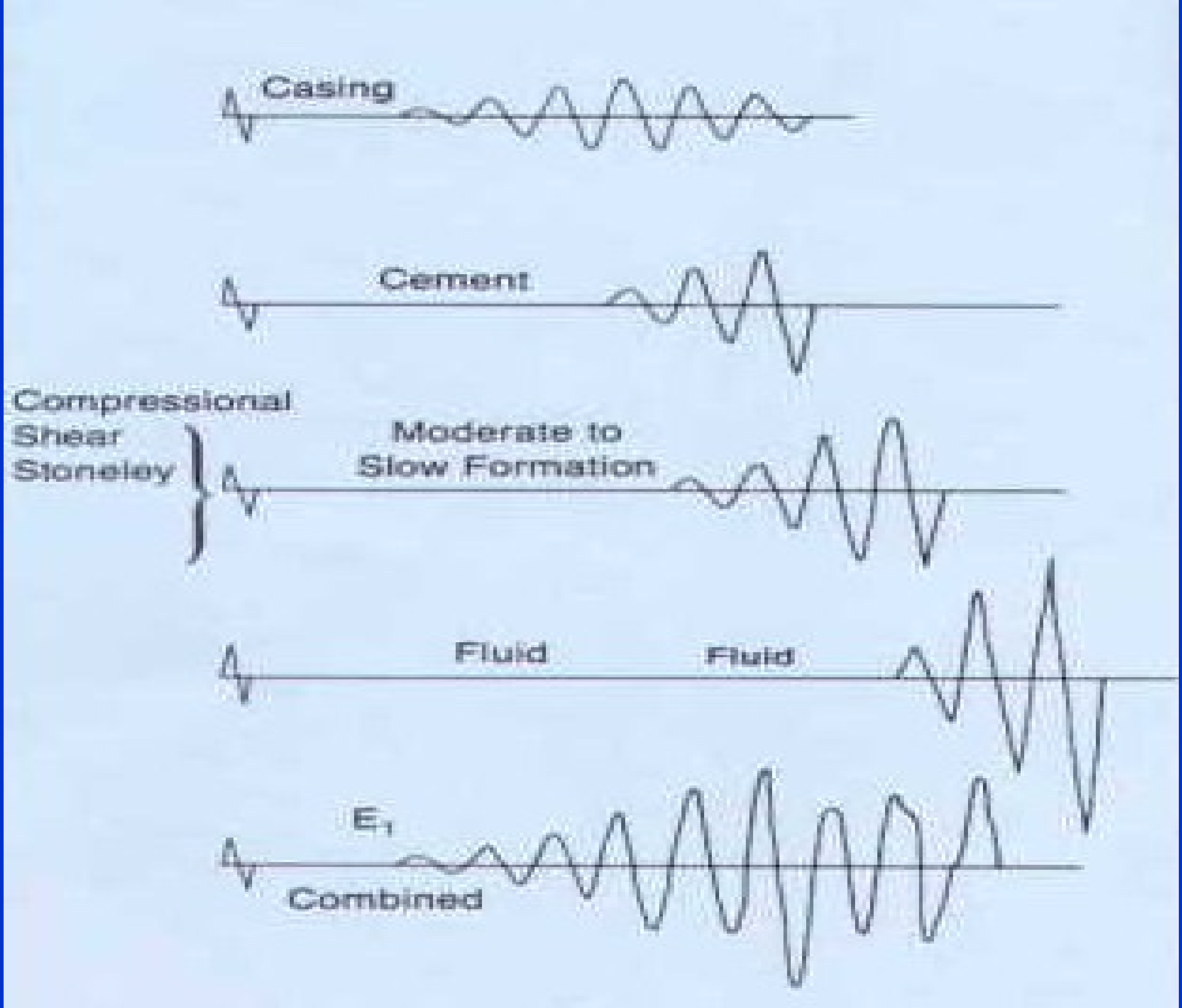
Principles of Cement Logs



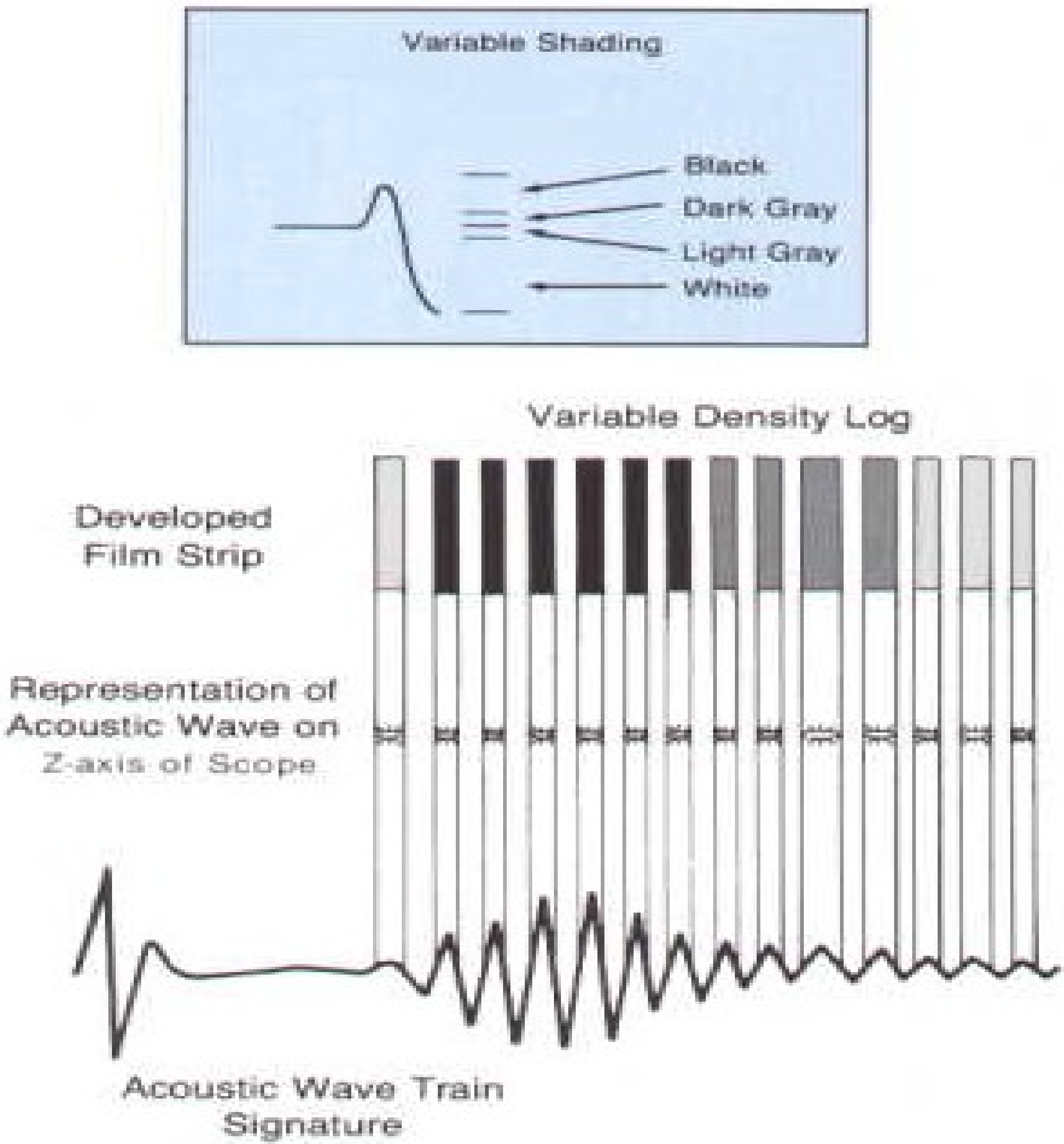
Amplitude: How Loud?



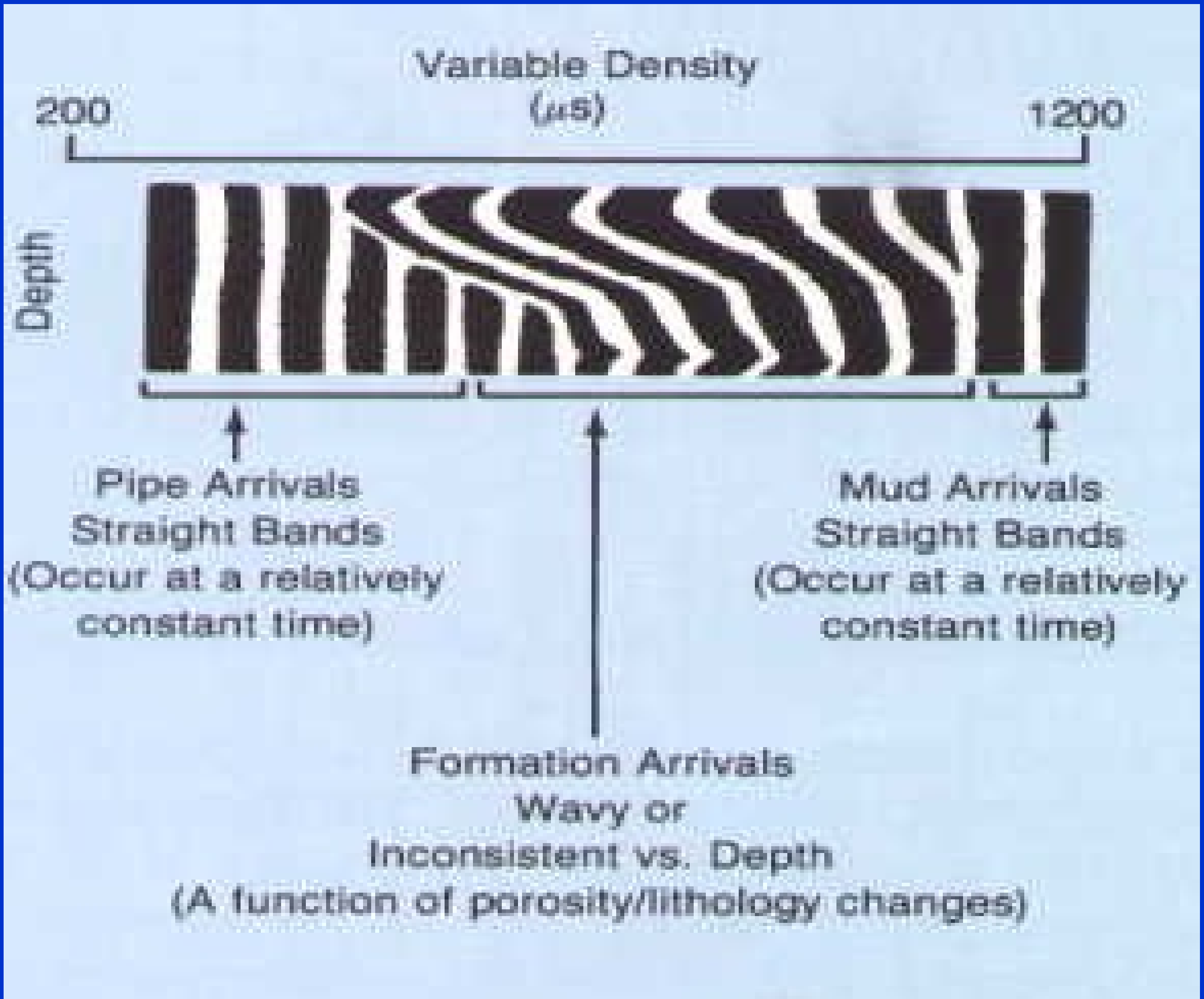
Energy Reflections: When and How Much?



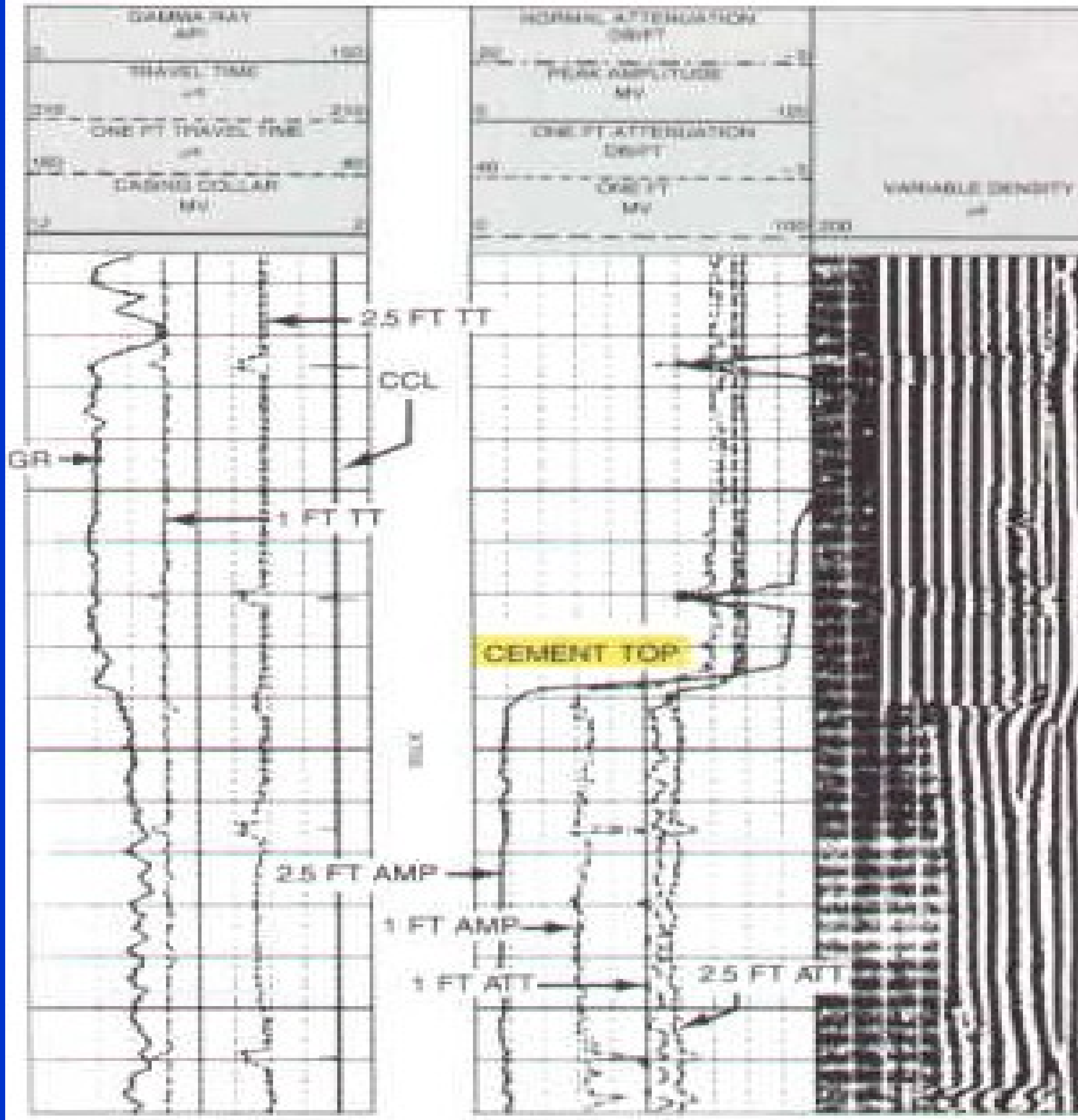
Louder Equals Darker



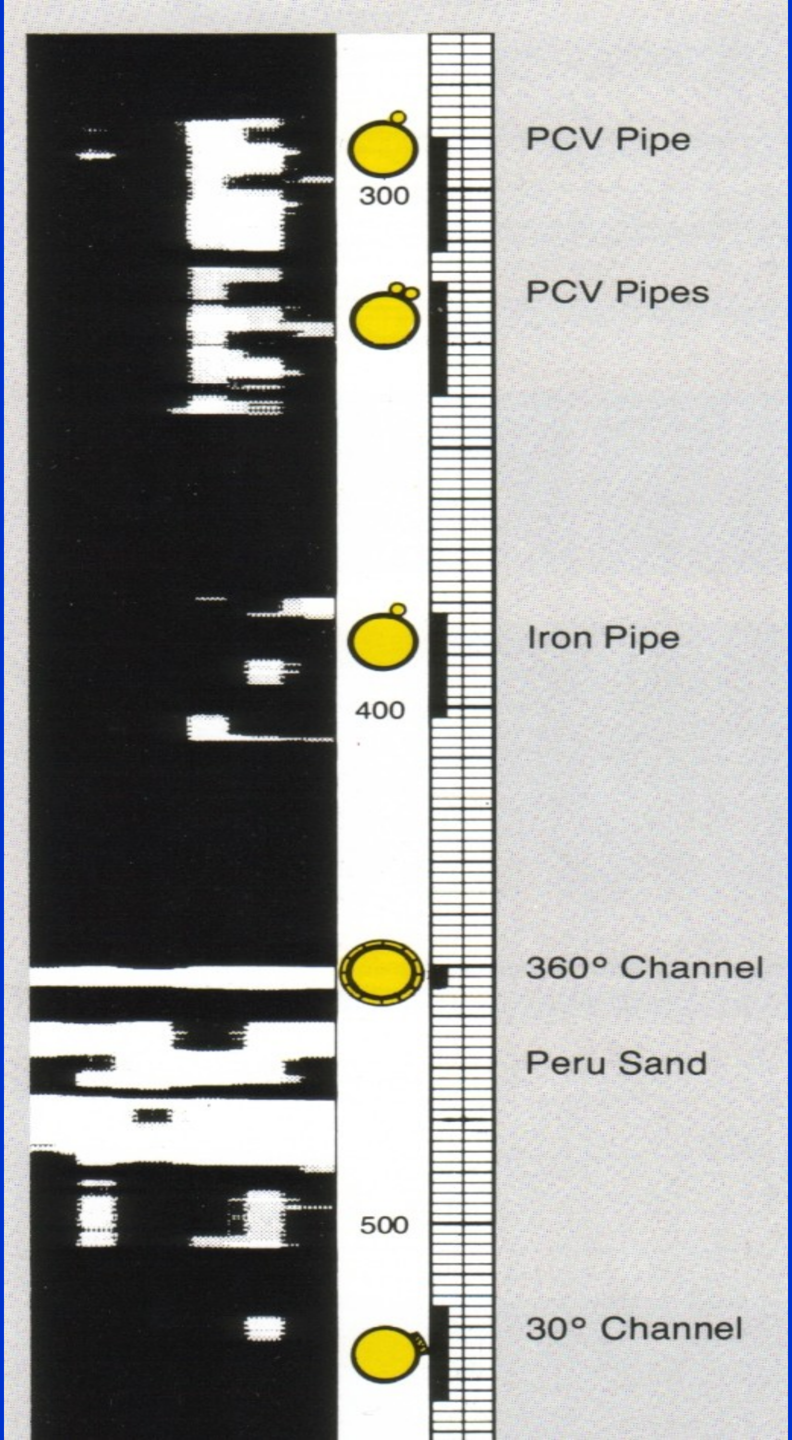
Variable Density Log



Typical CBL Cement Log (Faked?)



Typical 3rd Generation Cement Log



Miscellaneous

- Deviation checks
- Driving, testing, and coring program
- Proposed annulus fluid

State Class II Requirements

- Some States allow
  - Short or no surface casing
  - No tubing or no packer
- Minimum long-string cement
  - 100 feet?
  - Both injection and production wells
- Injection opposite uncemented zones provides pathway

State Class II Requirements

- 146.22 (c) field rules

  The [construction] requirements … need not apply if:

  (i) Regulatory controls for casing and cementing existed at the time of drilling of the well and the well is in compliance with those controls; and

  (ii) Well injection will not result in the movement of fluids into an underground source of drinking water **so as to create a significant risk to the health of persons**.

Technical Pitfalls

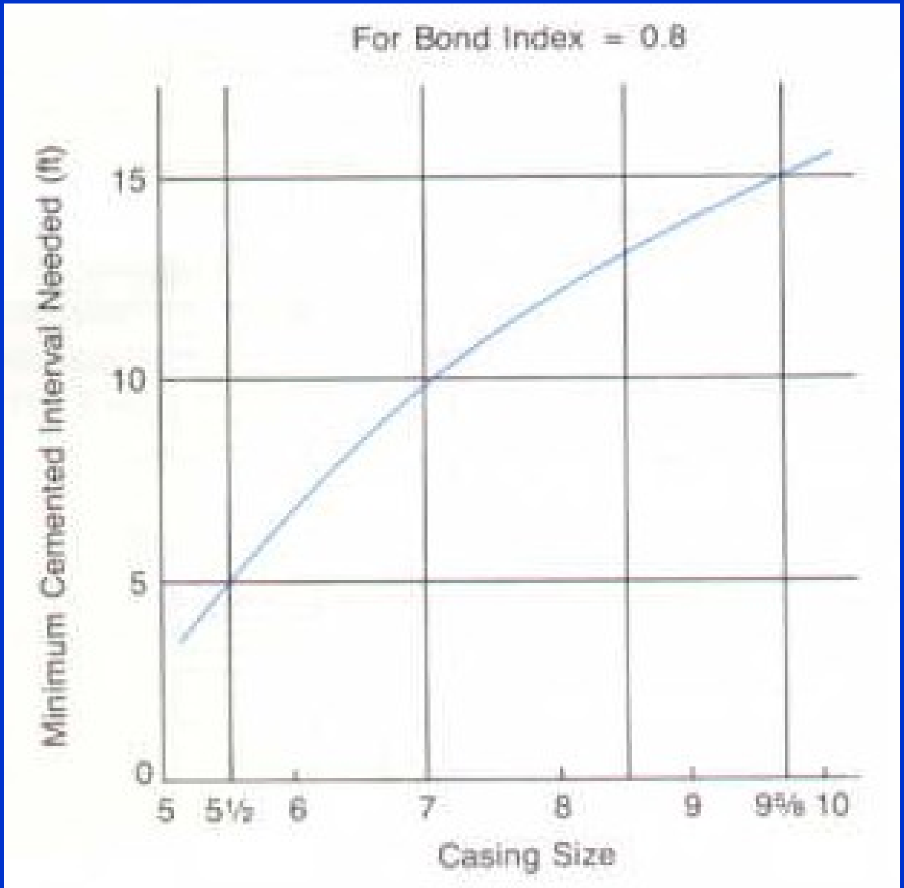
- Cement to surface: required, but rare?
- Reports of long-string cement to surface   (but cement fell)

Technical Pitfalls

- Incomplete displacement of the mud column (short-circuiting)
- “Top job” -- add cement to an incomplete or falling cement column
- Incomplete cement logs

Technical Pitfalls

"Continuous" cement

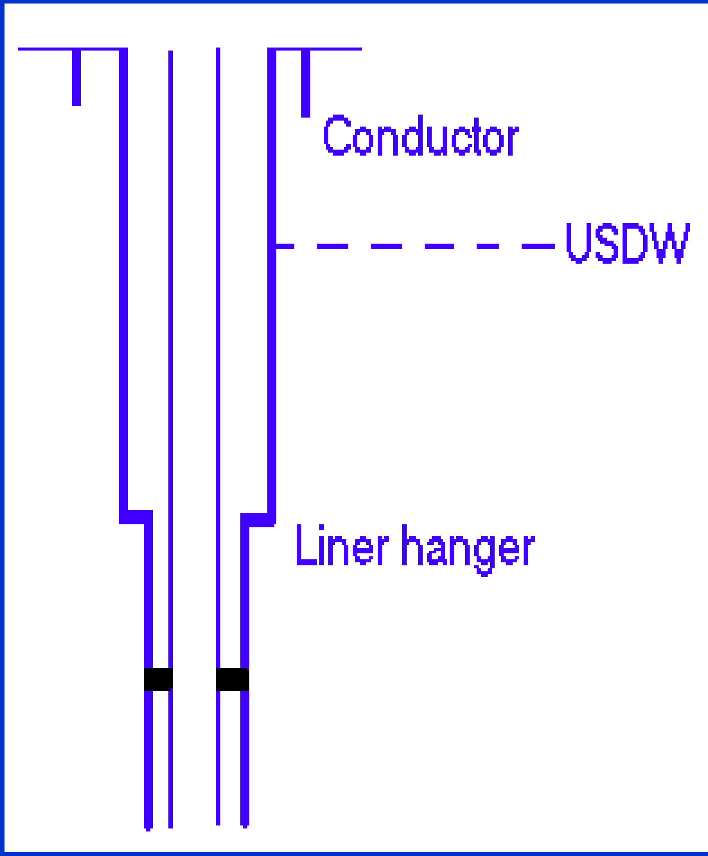


Technical Pitfalls

- Remedial “squeeze” cementing
  - Often tried but not always successful due to restrictions behind casing
  - Applicable for uncemented casing

Technical Pitfalls

- Packer set within 100 feet above injection interval
- Incomplete casing strings
- Used equipment?



Permit Review

- Design protects USDWs?
  - Regulatory prioritization
  - Full cement + tbg/pkr unless good reason
- Surface casing versus USDW base
- Cement coverage
- Packer placement
- Logs and sampling next section

Discussion

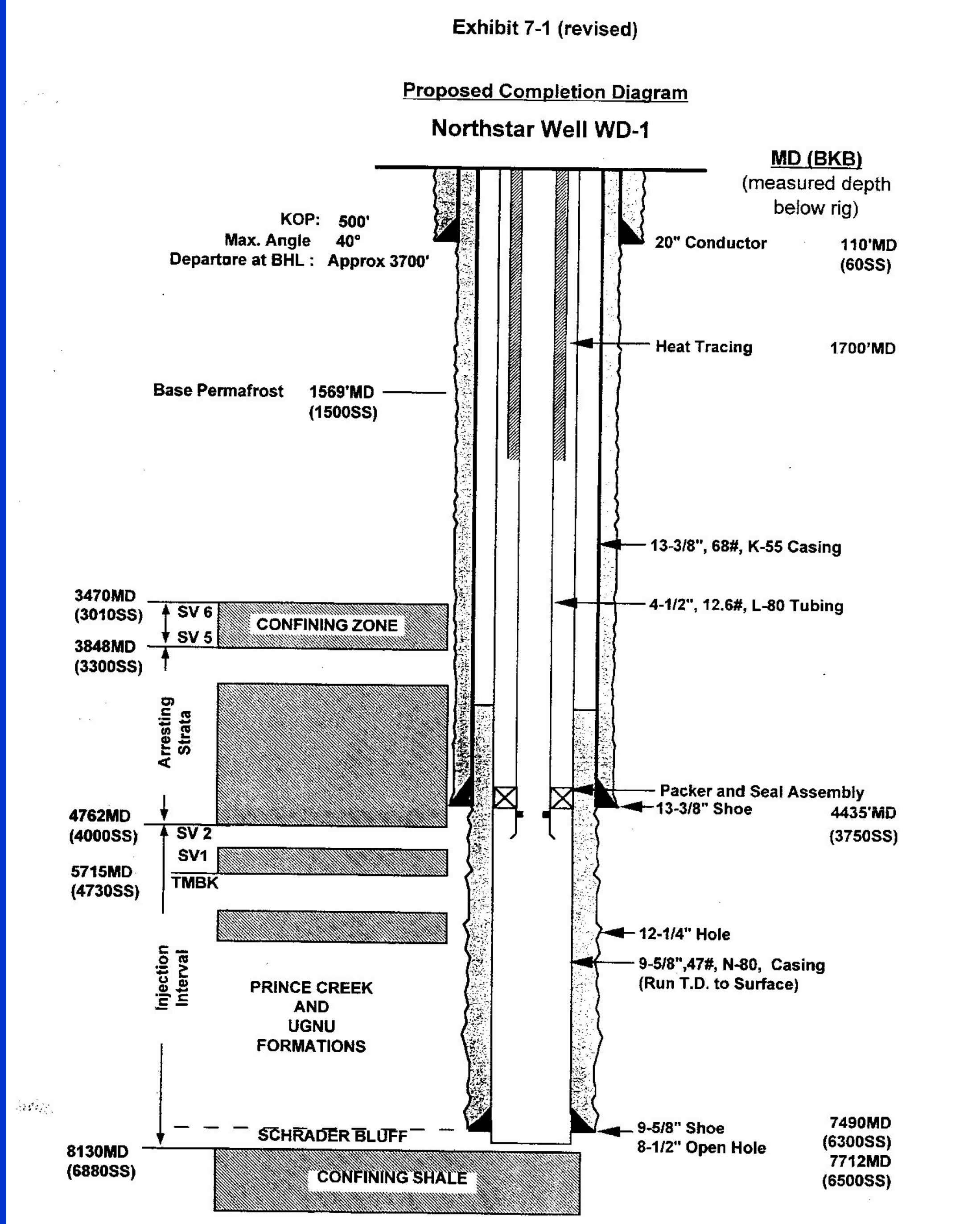


Exhibit 7-1 (revised)
Proposed Completion Diagram
Northstar Well WD-1
MD (BKB)
(measured depth below rig)
KOP: 500'
Max. Angle 40°
Departure at BHL : Approx 3700'
20" Conductor
110'MD
(60SS)
Heat Tracing
1700'MD
Base Permafrost
1569'MD
(1500SS)
13-3/8", 68#, K-55 Casing
4-1/2", 12.6#, L-80 Tubing
3470MD
(3010SS)
SV 6
CONFINING ZONE
SV 5
3848MD
(3300SS)
Arresting Strata
Packer and Seal Assembly
13-3/8" Shoe
4435'MD
(3750SS)
4762MD
(4000SS)
SV 2
SV1
5715MD
(4730SS)
TMBK
12-1/4" Hole
9-5/8",47#, N-80, Casing
(Run T.D. to Surface)
Injection Interval
PRINCE CREEK
AND
UGNU
FORMATIONS
SCHRADER BLUFF
9-5/8" Shoe
8-1/2" Open Hole
7490MD
(6300SS)
7712MD
(6500SS)
8130MD
(6880SS)
CONFINING SHALE

Exercise

ATTACHMENT "L" (Continued)

Excess Cement Volume for Surface Casing

The 9 5/8" surface casing was cemented to surface with 350 sxs of regular Class A cement. This volume is 40.5% in excess of the required annular volume as shown below:

$$\text{Vol. Req.} = \frac{HD^2 - PD^2}{183.33} \quad (L)$$

Where: Vol. Req. is the cement slurry volume required (ft^3)
HD is the hole diameter (in)
PD is the pipe diameter (in)
L is the desired length of the cement column (ft)

HD = 12.250 in
PD = 9.675 in
L = 937 ft

$$\text{Vol. Req.} = \frac{12.25^2 - 9.625^2}{183.3} \quad (937)$$

$\underline{\text{Vol. Req.} = 293.48\ ft^3}$

Vol. used = (sx)(yield)

Where: Vol. used is cement slurry volume used (ft^3)
Sx is the number of sacks of cement used (sx)
Yield is the slurry yield per sack of cement (ft^3)

Sx = 350 Sx
Yield = 1.18 ft/sx

$\underline{\text{Vol. used} = (350)\ (1.18) = 413\ ft^3}$

$$\%\ \text{Excess} = \frac{\text{Vol. used} - \text{Vol. req.}}{\text{Vol. req.}} \quad (100)$$

Vol. used = 413 ft^3
Vol. req. = 294 ft^3

$$\%\ \text{Excess} = \frac{413 - 294}{294} \quad (100) = 40.5\%$$

Lesson 12

Formation Testing Program

Formation Testing Program

- Requirements for new Class I wells in 40 CFR 146.12(e)
- Determine or calculate:
  - Fluid pressure
  - Temperature
  - Fracture pressure
  - Other physical and chemical characteristics of the injection matrix
  - Physical and chemical characteristics of the formation fluids

Formation Testing Program

- Requirements for new Class II wells or projects in 40 CFR 146.22(g)
- Determine or calculate
  - Fluid pressure
  - Estimated fracture pressure
  - Physical and chemical characteristics of the injection zone

Formation Testing Program

- Requirements for new Class III wells at 40 CFR 146.32(c) apply to injection zones that are naturally water-bearing
  - Fluid pressure
  - Fracture pressure
  - Physical and chemical characteristics of the formation fluids
- If the formation is not water-bearing, 40 CFR 146.32(d) requires only fracture pressure

Use of "Similar Data"

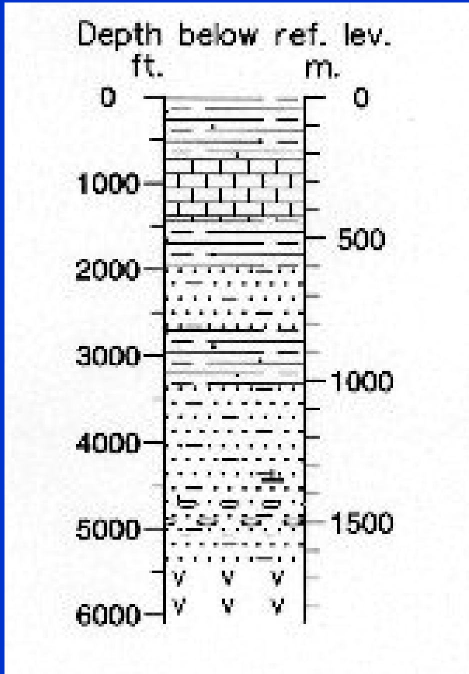
- In determining tests and logs to be conducted, may consider ". . .availability of similar data in the area of the drilling site. . ."
  - 40 CFR 146.12(d)(2), Class I
  - 40 CFR 146.22(f)(2), Class II
  - 40 CFR 146.32(b), Class III
  - 40 CFR 146.66, Class IH

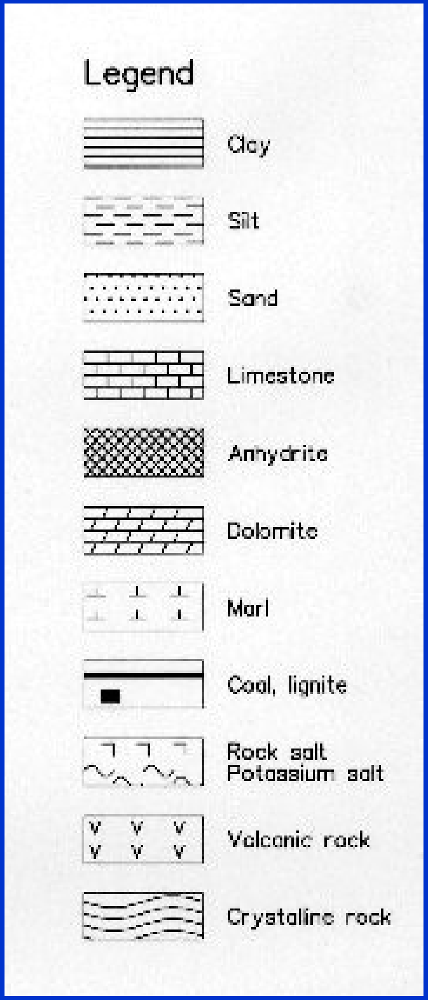
Data Obtained During Drilling and Completion

- Several opportunities to obtain site-specific data
- Data used to predict performance
- Test types
  - Rock and fluid sampling
  - Geophysical logging
  - Pressure and transient testing

Rock Sampling

- Mud and cutting analysis
- Sidewall cores
- Full diameter cores

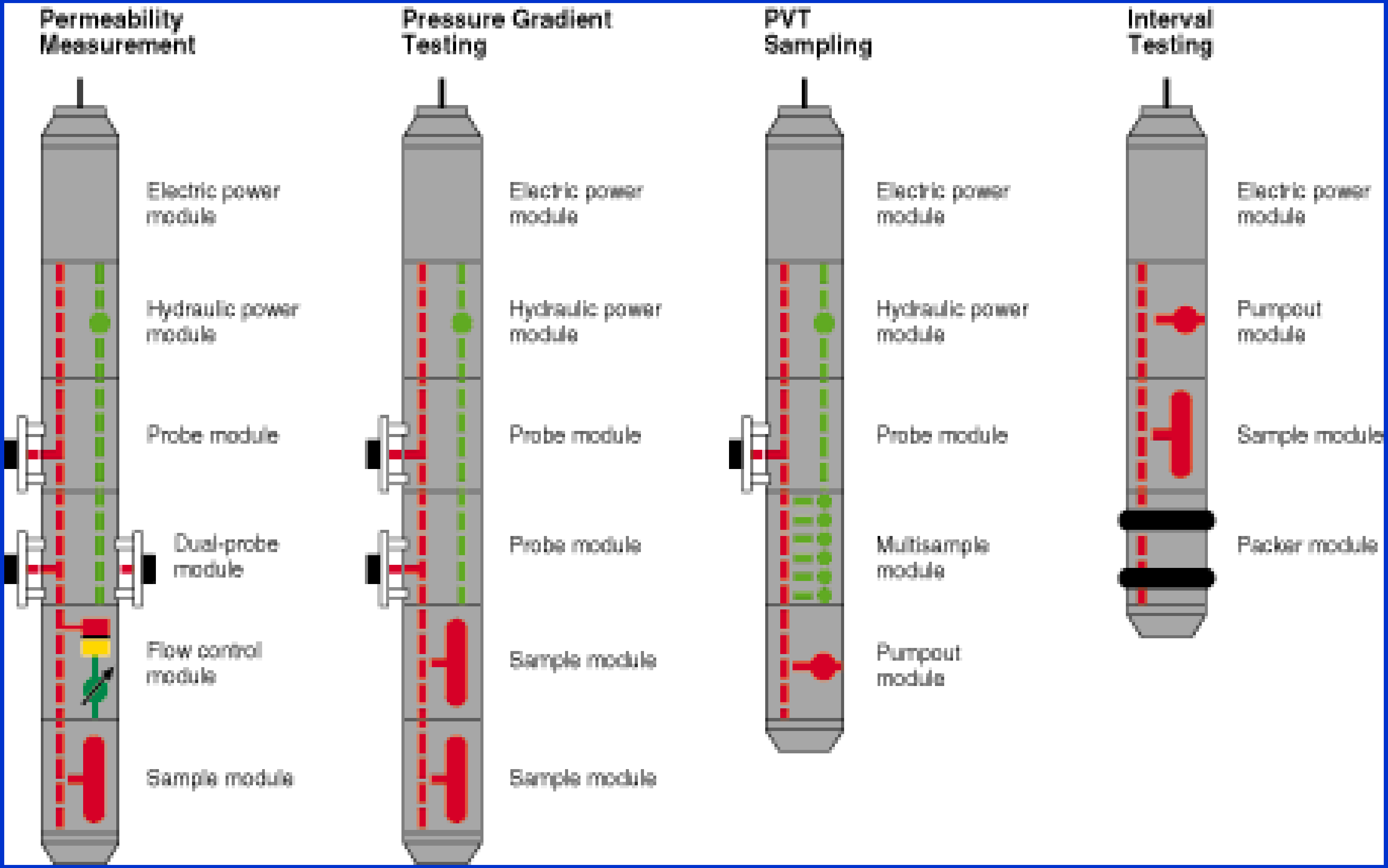




Fluid Sampling

- Drill-stem testing
- Nitrogen lift and swabbing
- Downhole formation sampler

New MFT Tool



Permeability Measurement
Electric power module
Hydraulic power module
Probe module
Dual-probe module
Flow control module
Sample module
Pressure Gradient Testing
Electric power module
Hydraulic power module
Probe module
Probe module
Sample module
Sample module
PVT Sampling
Electric power module
Hydraulic power module
Probe module
Multisample module
Pumpout module
Interval Testing
Electric power module
Pumpout module
Sample module
Packer module

Open-Hole Well Logs - Electrical

Method	Property	Application
• Spontaneous potential (SP)	• Electrochemical and electrokinetic potentials	• Formation water resistivity (Rw); shales and nonshales; bed thickness; shaliness
• Nonfocused electric log	• Resistivity	1. Water and gas/oil saturation 2. Porosity of water zones 3. Rw in zones of known porosity 4. True resistivity of formation (Rw) 5. Resistivity of invaded zone
• Focused conductivity log	• Resistivity	• 1-4; very good for estimating R† in fresh water or oil base mud
• Focused resistivity logs	• Resistivity	• 1-4; especiallly good in determining R† of thin beds • Depth of invasion
• Focused and nonfocused microresistivity logs	• Resistivity	• Resistivity of the flushed zone (Rxo) for calculating porosity • Bed thickness

Open-Hole Well Logs – Elastic Wave Propagation

Method	Property	Application
• Transmission	• Compressional and shear wave velocities • Compressional and wave attenuations	• Porosity; lithology; elastic properties, bulk and pore compressibilities • Location of fractures; cemend bond quality
• Reflection	• Amplitude of reflected waves	• Location of vugs, fractures; orientation of fractures and bed boundaries; casing inspection

Open-Hole Well Logs - Radiation

Method	Property	Application
Gamma ray	Natural radioactivity	Shales and nonshales; shaliness
Spectral gamma ray	Natural radioactivity	Lithologic identification
Gamma-Gamma	Bulk density	Porosity, lithology
Neutron-Gamma	Hydrogen content	Porosity
Neutron-Thermal Neutron	Hydrogen content	Porosity; gas from liquid
Neutron-Epithermal Neutron	Hydrogen content	Porosity; gas from liquid
Pulsed neutron capture	Decay rate of thermal neutrons	Water and gas/oil saturations; reevaluations of old wells
Spectral neutron	Induced gamma ray spectra	Location of hydrocarbons; lithology

Open-Hole Well Logs - Other

Method	Property	Application
Gravity meter	Density	Formation density
Ultra-long spaced electric log	Resistivity	Salt flank location
Nuclear magnetism	Amount of free hydrogen; relaxation rate of hydrogen	Effective porosity and permeability of sands; porsity for carbonates
Temperature log	Temperature	Formation temperature

Pressure-Transient Testing

- Provides averaged data for larger portion of reservoir
  - Build-up or draw-down
- Types of tests
  - Drill-stem test
  - Injectivity
  - Specialized (e.g., straddle-packer)

Objectives of Formation Testing

- Consider how much you need to know before asking for expensive tests
- Focus on real concerns
  - USDW, confining zone, and AoR
  - Cement
  - Detailed mineralogy and water chemistry
  - Fracturing or step test

Permit Review Essentials

- USDW stratigraphy and chemistry
  - Gamma, resistivity and SP logs
  - Verify or sample lowermost USDW
- Injection and confining zones
  - Stratigraphy: add density/neutron?
  - Basic mineralogy and properties: sidewall cores with complete analysis

Permit Review Essentials

- Detailed driller's and activity logs
- Short-term injection test
  - Initial BHP and skin
  - Analysis for Kh

Lesson 13
Stimulation Program

Chemical Stimulation

- Salts
  - Potassium chloride (KCl)
- Acid
  - Hydrochloric (HCl)
  - Hydrofluoric (HF)
- Organic solvents
  - Methanol or detergents

Design Criteria

- Prevent corrosion
  - Inhibitors reduce steel corrosion (but not cement)
- Reduce harmful side-effects
  - Iron precipitates, clay disaggregation
- Depth of beneficial effects
  - Sizing and staging of treatment chemicals
  - Maximum injection pressure limitations not applicable

Physical Stimulation

- Swabbing
  - Surging well using cups on tubing
- Hydraulic fracturing
  - Extreme pressure, specialized fluids, and proppants
- Shooting

Fracturing Design Criteria

- Require detailed fracture design
- Ensure confining zone integrity
  - Observe fracture limit for confining zone
- Ensure USDW integrity

Too Much Stimulation?

- Post-construction acid jobs improve injectivity
  - Dissolve precipitates and solids
- Acid jobs can also:
  - Dissolve cement in AoR
  - Create channels along borehole
  - Cause harmful reactions
  - Dissolve confining zone

Review Essentials

- Need or reason for stimulation
- Objectives and methods
- Stimulation chemicals
- Program to prevent
  - Corrosion
  - Cement dissolution
  - Harmful effects to injection or confining zone

Lesson 14

Proposed Operating Data

Section Outline

- Regulatory requirements
- Performance standard
- Components of injection pressure
- Exercise: calculate permit injection pressure
- Shorthand method
- Calculate permit injection rate and volume
- Monitoring injected waste

Attachment H

- Average and maximum daily rates and volume of the fluids to be injected
- Average and maximum injection pressure
- Nature of annulus fluid

Attachment H

- Class I wells
  - Source of injection fluids
  - Analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness
- Class II wells
  - Source of the injection fluid
  - Analysis of the physical and chemical characteristics

Attachment H

- Class III wells
  - Qualitative analysis and ranges in concentrations of all constituents
  - If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained

Performance Standard Classes I and III

- Pressure in the injection zone does not
  - Initiate new fractures or propagate existing fractures in the injection zone or confining zone
  - Cause movement of injection or formation fluids into USDW

Performance Standard Class II

- Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs.

Delta p (Δ p)

- Matthews and Russell (1967) show that pressure increase is greatest at the well, but decreases dramatically (log) with distance

$$\Delta p = 162.6 \ \frac{Q\,\mu}{k\,b} \left[\log \frac{k\,t}{\Phi\,\mu C r^2} - 3.23 \right]$$

Bottom Hole Pressure

- Bottom-hole pressure during injection (BHPI) consists of
  - Δ p (injection pressure at some Q) plus
  - Weight of the fluid column
    - Height of fluid x density, e.g.,

      4000 ft @ .4416 psi/ft = 1766 psi
- BHPI also expressed as gradient (psi/ft)
    - E.g., 1940 psi ÷ 4000 ft. = 0.485 psi/ft

Example: Allowable Injection Pressure

- Well depth: 4000 feet
- Thickness of interval (b): 50 feet
- Porosity (Φ): 30 percent
- Permeability (k): 400 md
- Injection rate (Q) = 1700 bbl/day
- Viscosity (μ) = 0.90 centipoise
- Duration of injection (t) = 87,600 hours
- Effective well radius (r) = .292 ft
- Reservoir storage (C) = 6.5×10^{-6} psi^{-1}
- Well tubing = 2.375”
- Injectate specific gravity = 1.02

Step 1: Injection Pressure

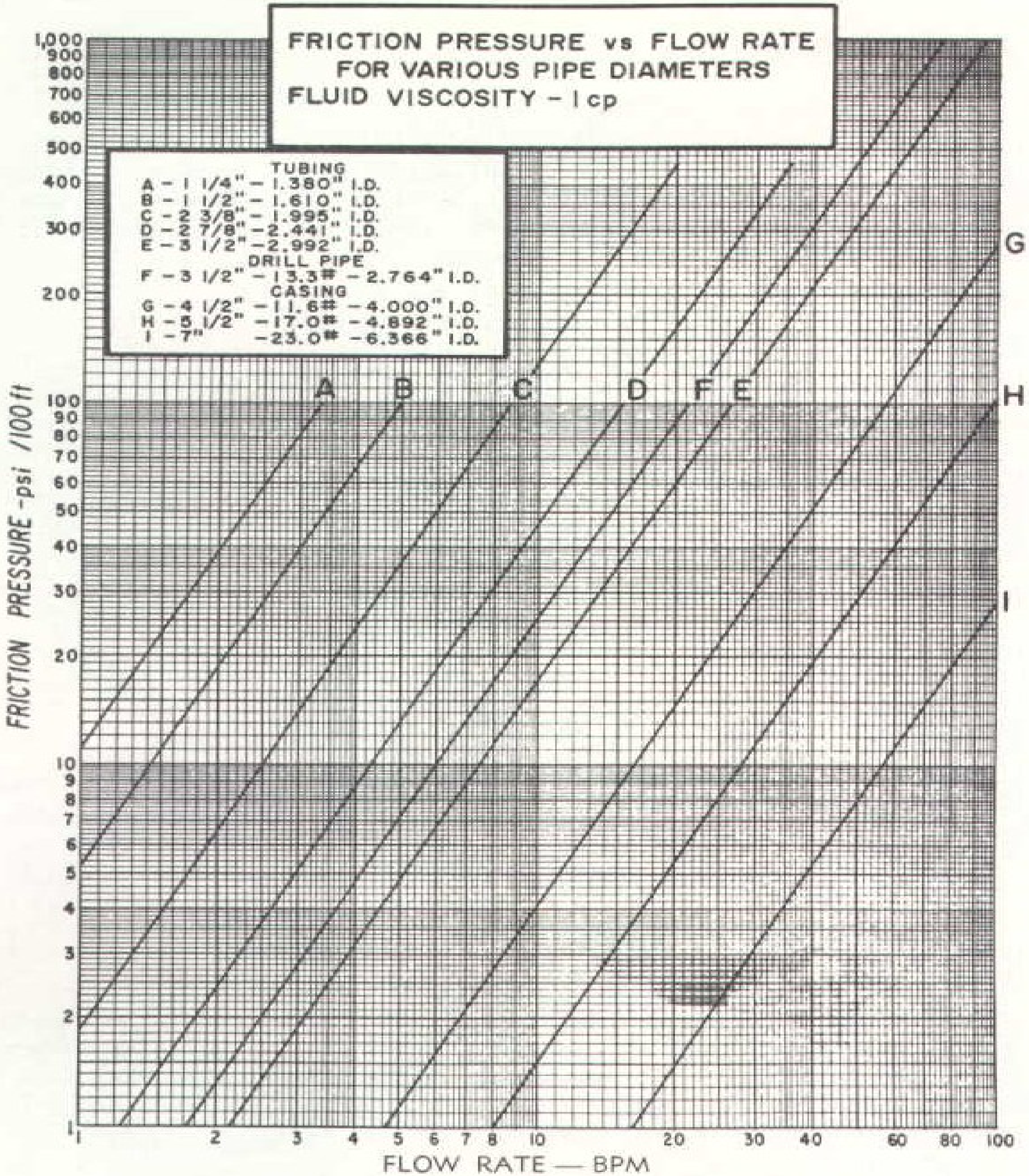
$$\Delta p = \frac{(162.6)\,(1700)\,(.90)}{(400)\,(50)} \quad x$$

$$\left[\ \log \frac{(400)\,(87600)}{(.30)\,(.90)\,(.0000065)\,(.292)^2} \ - \ 3.23\ \right]$$

Δ p = 138.6 psi at the injection face

Step 2: Friction Loss

Additional pumping pressure is needed to overcome frictional losses in the tubing (34 psi)



Friction Loss at Formation Face

- Friction losses also at the formation face (“skin”) (35psi)
- Δp + friction + skin = 207.6 psig @ wellhead (+ formation pressure)

Bottom Hole Pressure

- Static bottom-hole pressure (BHP)
  - Weight of the fluid column
    - Height of fluid x density, e.g.,

      4000 ft @ .4416 psi/ft = 1766 psi
- BHP also expressed as gradient (psi/ft)
    - E.g., 1766 psi ÷ 4000 ft. = .4416 psi/ft

Step 3: Operating WHIP

- Emplacement = Δ p + friction/skin (69 psig) + existing pressure (1795 psig) = 2003 psig
- Fluid weight using specific gravity
  - 1.02 S.G. = .4416 psi/ft = 1766 psig
- WHIP = emplacement pressure – fluid weight = 237 psig

Step 4a: Bottom Hole Pressure (Injection)

- Bottom-hole pressure during injection (BHPI) consists of
  - Δ p (138.6 psig)
  - Skin effect (35 psig) plus
  - Weight of the fluid column (1766 psi)
    - (4000 ft @ .4416 psi/ft = 1766 psi)
- BHPI = 1940 psig, or .485 psi/ft
  - 1940 psi ÷ 4000 ft = 0.485 psi/ft

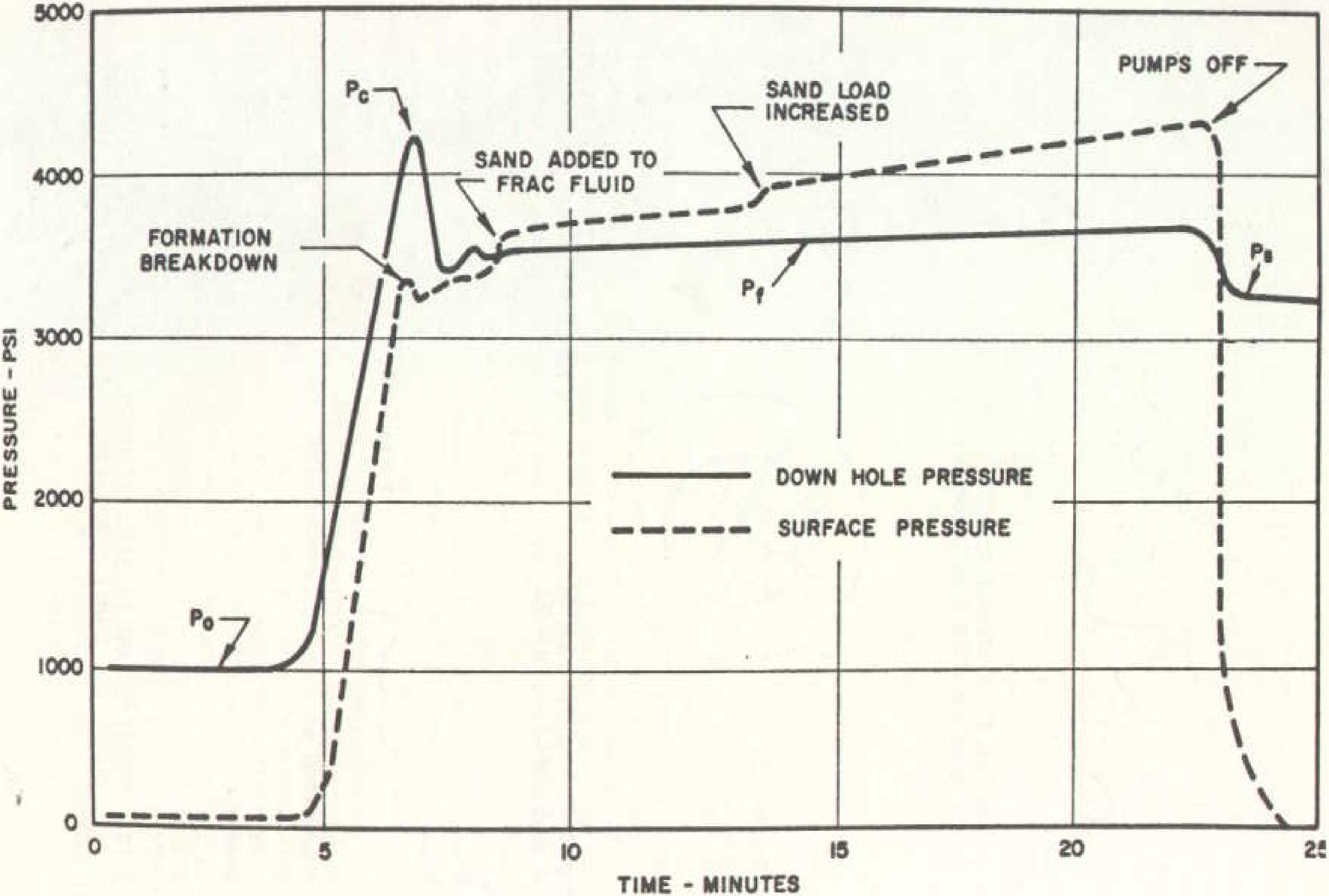
Fracture Gradient

- Injection pressure can not exceed the fracture pressure
  - Injection zone (Class I)
  - Upper confining zone (Class II)
- Fracture pressure is unique for every formation and time
  - .65 to >1 psi/ft

Fracture Pressure

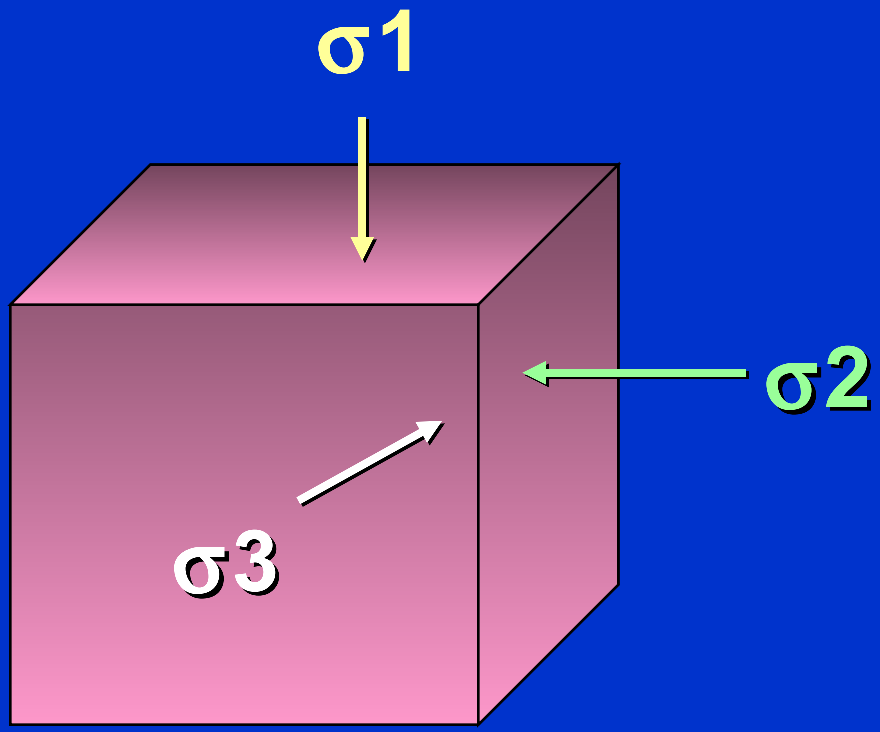
- Finding fracture pressure
  - Published data (oil and gas industry)
  - Measured downhole using injection test
  - Estimated

Step Testing and Fracture Logs



Estimating Fracture Gradient

- Vertical stress
- Least and most horizontal stresses



σ1 > σ3 > σ2

Hubbert and Willis (1972)

- Fracture orientation perpendicular to least principal stress
- Fracture gradient is usually from 0.64 to 0.73 psi/ft in typical oil sands
- More for shale-rich, hard rock, or thrust areas (up to 1.0 psi/ft)

Step 4b: Calculate Permit WHIP

- Operating WHIP = 237 psi
- Allowable WHIP (for 1.02 S.G.) = 654 psig
  - Fracture pressure (2560 psi using .64 psi/ft gradient @ 4,000 feet)
  - Minus BHPI (1940 psi)
  - Plus tubing friction (34 psi)

Shorthand Version

- Maximum WHIP = fracture pressure – BHP
  - Injection rate not considered
- For example:
  - .64 x 4000 = 2560 fracture pressure
  - .4416 x 4000 = 1766 BHP
  - 2560 – 1766 = 794 psig maximum WHIP

Maximum Allowable Injection Rate

- Maximum rate usually specified by applicant
  - Long WHIP method already solved using rate
- Injection test at maximum WHIP
- Back-calculate using results of shorthand WHIP and Craft and Hawkins

Matthews and Russell

$$Q = \frac{\Delta p\, kb}{162.6\, \mu} \left[\log \frac{1}{\dfrac{k\, t}{\Phi\, \mu C r^2}} - 3.23 \right]$$

$$Q = \frac{(794)(400)(50)}{(162.6)(0.9)} \left[\log \frac{1}{\dfrac{(400)\,(87600)}{(.30)\,(.90)\,(.0000065)\,(.292)^2}} - 3.23 \right]$$

Q = 9740 BPD @ 794 psi maximum WHIP

Maximum Injection Volume

- Specified by applicant?
- Estimated from maximum rate
  - Use 24- or 10-hour days, 5 or 7-day weeks

Issue: Limiting WHIP for Corrective Action

Consider unplugged well at r = 300 feet

1) BHP divided by density gradient
   - 1795 / .460 = 3902 feet of head
2) Subtract (well depth – depth to USDW)
   - 3902 – (4000 – 400) = +302 feet of head @ usdw base
   - Convert to psi: 302 x .460 = 138.9 psi
3) USDW head (or sat. thickness) x density ratio
   - 426 feet x (.433+.460/2) = 190.2 psi @usdw base
4) Compare 2 and 3
   - 138.9 psi upward versus 190.2 downward
   - 51.3 psi downward *before injection begins*

Δp @ r=300ft, t=10yrs < 51.3 psi

$$Q = \frac{\Delta p\, kb}{162.6\,\mu} \left[\log \frac{1}{\frac{k\,t}{\Phi\,\mu C r^2}} - 3.23 \right]$$

$$Q = \frac{(51.3)(400)(50)}{(162.6)(0.9)} \left[\log \frac{1}{\frac{(400)\,(87600)}{(.30)\,(.90)\,(.0000065)\,(300)^2}} - 3.23 \right]$$

Q = 1370 BPD limit to achieve 51.3 psi @300 feet

- or limit BHP in injector or monitoring well

Issue: Conservative Values and Safety Factors

- Is a safety factor necessary to protect USDWs?
  - 75 percent of fracture gradient
  - Minimum rather than average values
  - 10-hour days
  - Many others

Monitoring Injected Waste

Injectate Characteristics

- Permit writers review injectate characteristics for monitoring requirements and compatibility
- Permit application includes injectate information
  – Injectate rate, volume and pressure
  – Analysis of characteristics: physical, chemical, biological and/or radiological, depending on class of well

Monitoring Injectate and Injection Parameters

- All injected fluids must be monitored
- Monitoring requirements vary by well type
- Monitoring parameters
  - Injection rate
  - Injection pressure
  - Monthly and cumulative injected volume
  - Annulus pressure and volume
  - Waste characteristics such as density, pH, and other parameters

Injectate Monitoring

Measurement	Monitoring Methods	Comments
• pH	• Grab sample	• Measure in the field; influences corrosivity and well construction materials
• TDS	• Grab sample	• Compatibility with injection zone
• Chemical content	• Generator knowledge; field sampling	• Representativeness; potential to be hazardous waste
• Temperature	• Grab sample	• Field measurement; formation and well construction issues
• Compatibility and reactivity	• Grab or composite, depending on waste stream	• Formation and construction component influences

Monitoring Waste Parameters

Subsurface Waste Interactions

- Permeability reduction
  - Precipitates or polymers
  - Clay swelling
- Permeability increase: Dissolution of matrix minerals
- Gas generation
  - Reduce permeability
  - Blowouts
- Adsorption or desorption: Immobilize, exchange, retard solutes

Changes in Fluid (Class III)

- Attachment N provides expected changes in fluid
  - Pressure
  - Native fluid displacement
  - Direction of movement of injection fluid

Class V Well Operating Data Evaluation

- Large-capacity cesspools are not allowed to be in operation in DI States after April 2005; all new wells prohibited as of April 2000
- New motor vehicle waste disposal wells prohibited after April 2000
- Existing motor vehicle waste disposal wells in critical ground water areas subject to closure or permitting

Motor Vehicle Waste Disposal Well Limitations

- If allowed to continue to operate in critical ground water area, must be permitted
- Operations limited:
  - Meet MCLs and other health based standards at point of injection
  - Monitor injectate and sludge
  - Implement best management practices (BMPs)

Lesson 15
Proposed Injection Procedures

Injection Procedures

- Describe the proposed injection procedures, including pump, surge tank, etc.
- Include operating procedures and contingency plans

Importance of Procedures

- Equipment used must be dependable and durable
- Automatic shut-down and emergency response are critical for protection of environment

Contingency Plans: Injectate Concerns

- Source and type of injectate
- Method of delivery (truck, pipeline)
- Off-load equipment and procedures
- Waste screening
- Manifests

Contingency Plans: Processing and Pre-Treatment

- Oil-water separation
- Filtration
- Storage
- Treatment equipment and methods
  - RCRA §3004(m) treatment
  - Reagent storage
  - Sludge handling and disposal
  - Air emissions

Contingency Plans: Injection and Shut-In

- Pump specifications
- Back-flow prevention
- Rate and pressure limitation
- Shut-in methods

Contingency Plans: Emergency Procedures

- Spill prevention and containment
- Loss of mechanical integrity
- Exceed maximum rate or pressure
- Auto alarm and/or shutdown
- Emergency contacts

Automatic Shut-Down

- Typically monitor rate, pressure, or MI
  - Requires continuous monitoring, usually of electronic devices
- Limitations
  - Complex shutdowns
  - Expensive

Automatic Shut-down

Automatic Shut-Down

- Benefits
  - Limits versus trust
  - Limits versus effects of violation
  - Corrective action involved
- Auto alarm appropriate for every well

Emergency Shut-Down

- Notification of excursion or MI loss
- Specific response procedures
- Response time
- Procedures to secure waste
- Subject to inspection and rehearsal

Documentation

- Accurate diagrams of system
- Complete description of alarm system; know “internal” from “permit” alarms
- Response procedures and proper notification when shut-down occurs
- Schedule for testing system and calibration of components as appropriate

Lesson 16

Plans for Well Failures

Attachment O Instructions

- Contingency plans (proposed plans, if any, for Class II) to prevent migration of fluids into any USDW
  - Shut ins
  - Well failures
- Provides assurance of existing and future well integrity

Mechanical Integrity

- 40 CFR 146.8(a):

  “No significant leak in casing, tubing, or packer

  and

  No significant fluid movement into USDW through vertical channels adjacent to injection well bore”

What is Required?

- All wells are required to demonstrate external and internal MI on a regular basis
- Frequency and acceptable tests vary among well classifications

Types of Well Failures: Tubing and Packer

- Most common (80 percent)
- Easily detected by annulus monitoring or APT
- Contains leaked injectate
- Located and fixed by pulling tubing and packer

Types of Well Failures: Casing Failures

- 12 to 20 percent of MI failures
- APT detects, but can not tell from tubing and packer leaks
- Located with bridge plug
- Repaired by liner, squeeze, or recompletion and sidetrack
- Uncontained leak (threat to USDW?)

Types of Well Failures: Cement Failure

- Migration captured
  - Indirect connection to USDW through conduit in capture zone?
- Direct connection to USDW through uncemented or poorly cemented casing
- Detect with RAT or other external MIT (Class I)
  - Prevented with cement logs or records during permitting
- Repaired by squeeze or recompletion

MI – Part 1 (Internal)

Testing Method	What is Evaluated?	Comments
• Annulus pressure test • Ada • Water-in-annulus	• Casing, tubing and packer leaks	• Small leaks may not be readily detected? • Casingless Class II in Regions 2 & 3 • Ohio Class II

MI – Part 2 (External)

Indirect Evaluation	What is Evaluated?	Comments
• Cement evaluation tools and cement bond logs	• Overall Cement integrity	• Must evaluate over time
• Cement records	• Only allowed for Class II and III	• Replaces Part 2 MIT demonstration requirement

MI – Part 2 (External)

Testing Method	What is Evaluated?	Comments
• Radioactive tracer test	• Internal leaks, behind pipe flow	• Very useful tool
• Temperature	• Behind pipe flow	• Temperature contrast between injected test fluid and formation fluid required for conclusive results

MI – Part 2 (External)

Testing Method	What is Evaluated?	Comments
• Noise	• Behind pipe flow	• Very limited due to small zone heard by tool
• Oxygen activation	• Behind pipe flow	• Calibration crucial

Know What You Are Seeing!

- MITs are crucial to ensuring on-going well component safety *but* they only see within inches of the wellbore
- MITs do not replace siting criteria
- Failure can occur beyond the wellbore environment that can contaminate USDWs
- MITs are one part of an injection well's multiple barrier set to protect USDWs
- All MIT results evaluated in conjunction with other well data

Annulus Monitoring

MIT Guidance

- Many procedural differences among States and Regions, well classes
- Annulus pressure test
  - Test pressure, duration, and variance
- Radioactive tracer test
  - Moving versus stationary, stations, flow

Lesson 17
Monitoring Program

Monitoring Program

- Maps of wells
- Monitoring devices
- Sampling frequency
- Parameters measured
- Manifold monitoring, if applicable

Monitoring Requirements: Class I (40 CFR 146.13)

- Analyze injectate (at unspecified frequency) for representative data
- Use continuous recording devices
  - WHIP, rate, volume, annulus
- Conduct MITs every 5 years
- Put monitoring wells in USDWs?
- Report quarterly

Monitoring Requirements: Class II (40 CFR 146.23)

- Monitor nature of injectate (at unspecified frequency) for representative data
- Observe WHIP, rate, volume
  - Monthly for II-R
  - Weekly for II-D
  - Daily for II-H and cyclic steam
- Conduct MIT (APT) every 5 years
- May use manifold monitoring for II-R and II-H
- Report annually

Manifold Monitoring

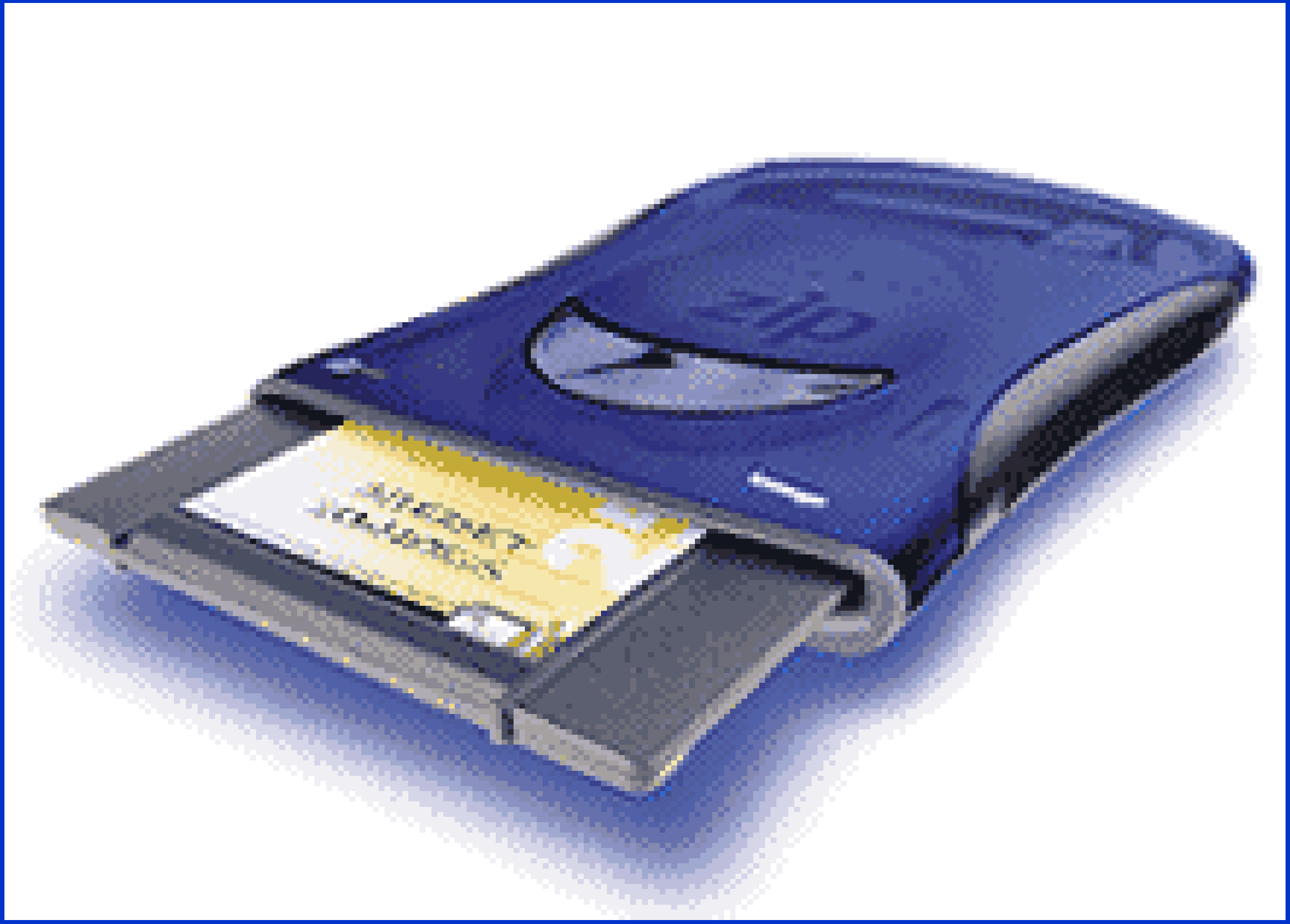
- Wells usually connected by common piping network; monitor at central location rather than well-by-well
- Injection characteristics at the well are different (usually less pressure) from those at the manifold
- Operator must demonstrate comparability

Monitoring Requirements: Class III (40 CFR 146.33)

- Monitor nature of injectate (at unspecified frequency) for representative data
- Monitor WHIP and rate or volume every 2 weeks **OR** meter and daily record injection and production volumes
- MIT every 5 years for salt solution mining only
- Fluid level and water quality every 2 weeks
  - Quarterly for collapse in USDW (146.32.g)
- May use manifold monitoring
- Report quarterly

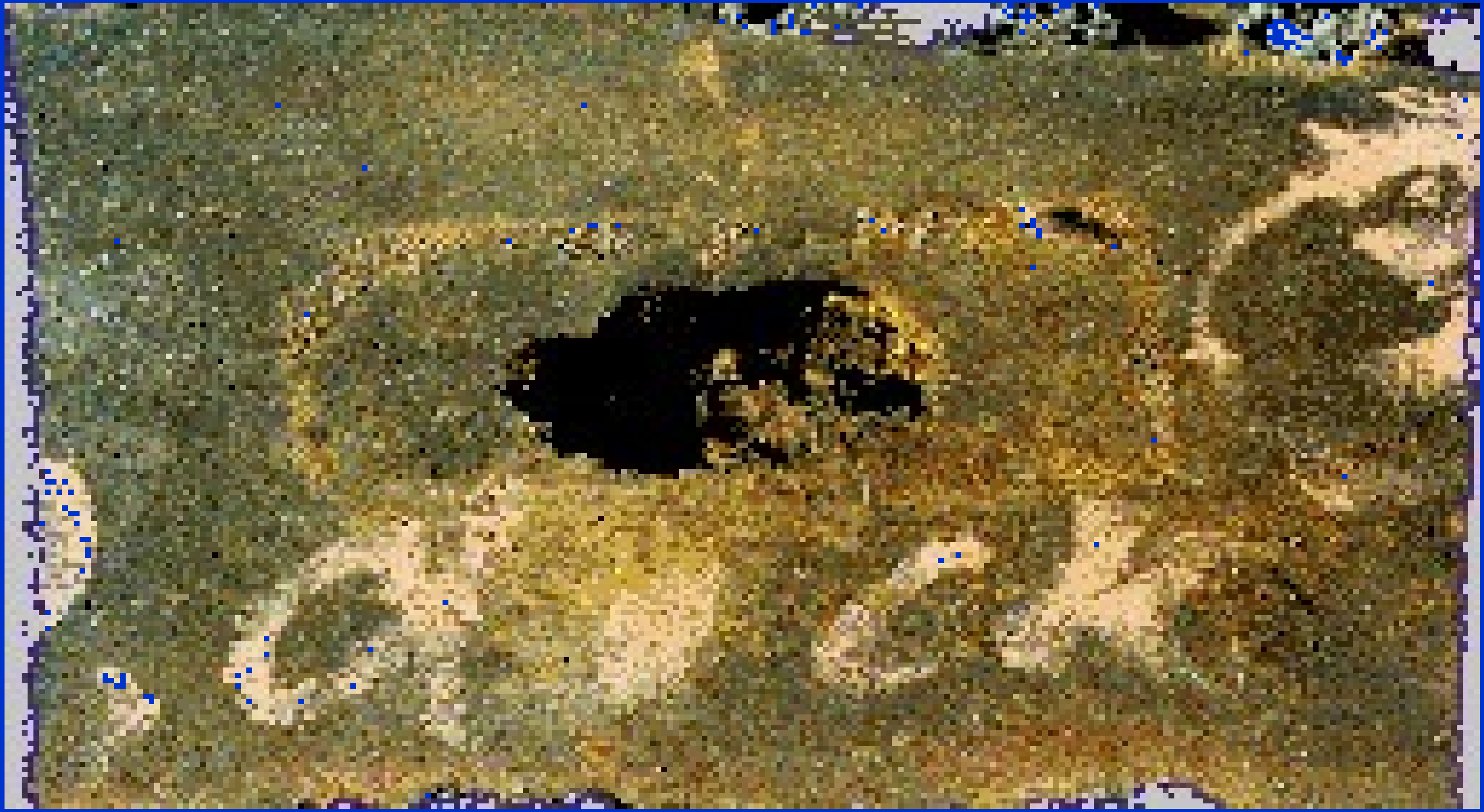
Digital Monitoring

Reporting Methods and Media



Annulus Monitoring

Corrosion Monitoring



Monitoring Wells

- Monitor injection zone
  - Pressure, waste front, waste decomposition
- Monitor above confining zone
  - Waste migration
- Monitor USDWs
  - Presence of waste
- Class III monitoring necessary

Monitoring Wells: Problems and Limitations

- Expensive (approach cost of injector)
- Small capture radius unless continuous pumping (water disposal)
- Path for migration

Is There a Real Need for a Monitoring Well?

- Injection zone
  - Pressure, waste
- Deep USDW/saline zone
  - Capture radius, conduit
- USDW
  - Too late

Uses of Monitoring Wells

- RCRA monitoring in upper USDW
- Corrective action
- Known migration
  - Use other drilling on site for monitoring
- Florida
  - Poor confinement versus need for injection
- Concessions?

Review Essentials

- Monitoring and reporting versus regs
  - Specific to well class
- Details of annulus system
- Reporting format (specify!)
- Special conditions
  - pH, corrosion, density
  - More MITs!

Injectate Monitoring: Exercise

- Class I-H commercial disposal well
- High waste acid content
- Injection into dolomite cemented sandstone, through fiberglass injection tubing with standard steel casing
- What would you require the operator to evaluate regarding injectate content? How often?

Lesson 18
Plugging and Abandonment Plan

P&A: OPERATOR's Burden, not EPA's

- P&A is 100 percent the operator's responsibility
- Careful review and maintenance of plan to be implemented is critical to ensure EPA doesn't get stuck with the tab
- Temporary cessation of injection may not require P&A

Requirement for P&A

- Plugging must occur in a way that will not allow movement of fluids into or between USDWs
- Must use cement
  - Class III wells may use other plugging materials with EPA approval
- Temporary cessation of injection may not require P&A

Plugging Methods

- Cement plugs emplaced in the well by:
  - Balance method
  - Dump bailer method
  - Two-plug method
  - Alternative approved method

Other Conditions

- Well must be in static equilibrium
- Class I, II and III permit must include P&A conditions, with a plan submitted by applicant. May include in Class V permit
- Plan must be submitted to EPA 30 days prior to closure for large capacity cesspool and motor vehicle waste disposal Class V wells

Plan Content

- Provide details of proposed plugging method
- Demonstrate movement of fluids into or between USDWs will not occur after plugging
- For Class V wells, sampling and analysis may be necessary prior to closure

Costs of Plugging and Abandonment

- Permit application required to include documentation of owner/operator’s financial ability to properly plug and abandon the well
- Additional discussion of requirements for financial demonstration provided in Section 19.0 of this course

Additional Class IH Requirements

- Class IH wells have additional requirements for well closure
- 40 CFR 146.71 lists the requirements for closure
- Post-closure plan also required for Class IH wells as part of the permit application (see 40 CFR 146.72)

Get It into the Administrative Record

- Documentation of verification of cement quantity
- Comments and responses
- Updated plans submitted during permitting process

Lesson 19
UIC Financial Responsibility

UIC Financial Responsibility

- Required for all permitted Class I, II and III UIC wells (§144.52(a)(7)); optional for Class V wells, at Agency discretion
- Most stringent requirements for Class I hazardous waste disposal wells
- Variety of different mechanisms
- Separate and distinct from closure authority (§144.52(a)(9))

Financial Responsibility Regulatory Requirements

- 40 CFR 144.52(a)(7)
- 40 CFR 144.60-.70 (Subpart F)
- 40 CFR Part 146

- Basic requirement for all Class I, II, III UIC wells
- Specific requirements for Class I hazardous waste UIC wells
- Reference to §144.52
- Financial responsibility for post-closure for Class I H

Financial Responsibility Requirements

- Class II oil- and gas-related injection wells
  - Acceptable options for Class II wells
  - Specific information on each acceptable type
  - Available on-line at: **http://www.epa.gov/r5water/uic/r5_02.htm**

40 CFR Part 146 Class I H UIC Requirements

- §146.70(a)(17)
- §146.71(a)(3)
- §146.72(a)(3)
- §146.73

- Demonstrate resources for closure and post-closure care
- Assure financial responsibility for closure
- Assure financial responsibility for post-closure care
- Comply with specific post-closure financial requirements

Permit Writer's Responsibilities

- Determine that the amount of assurance is adequate
- Determine that the type of mechanism is appropriate
- Determine that the wording of the instrument complies with the regulations
- Determine that all parts of the instrument are in place
- Decide if a permitted Class V well needs to have financial assurance in place

Closure Plans and Cost Estimates

- Financial responsibility amounts are directly related to cost estimates in the closure and post-closure care plans
- A variety of factors influence costs
  - Inflation
  - Well design changes (drilling out to increase depth)
  - Equipment costs
  - Site-specific well issues

Reviewing the Cost Estimate

- Review the cost estimate to determine whether the amount of the financial assurance is adequate
- Ensure that all activities in the plan are covered in the cost estimate
- Ensure that costs are reasonable and valid

What Mechanisms Are Allowed for Hazardous Waste Wells?

- Trust fund
- Surety bond with standby trust
- Letter of credit with standby trust
- Insurance
- Corporate guarantee
- Financial test

What Mechanisms Are Allowed for Class II Injection Wells?

- Surety bond with standby trust
- Financial guarantee bond
- Performance bond
- Letter of credit with standby trust
- Irrevocable trust
- Financial statement

What Mechanisms Are Allowed for Other Injection Wells?

- Surety bond
- Other adequate assurance
  - Financial statement
  - Other materials

Which One to Use?

- The owner/operator chooses which mechanism to use
- The selected mechanism may be changed at any time with EPA's approval
- An established instrument is not terminated by the Director until a new instrument is in place and approved

Reviewing the Mechanism

- Does the company meet the requirements for the type of mechanism selected?
- Is the stand-by trust established where required?
- Has the mechanism been set up properly?

Wording of Instruments

- 40 CFR 144.70 provides the **EXACT** wording for Class I H instruments
- Applies to instruments for closure and post-closure care
- Wording, including punctuation, must be in compliance
- Wording may be used as a guide for instruments for other well classes

Release from Financial Assurance

- Completion of closure (or post-closure) according to the approved plan must be certified by an independent professional engineer prior to the release
- The obligation to maintain financial assurance survives the permit termination and cessation of injection

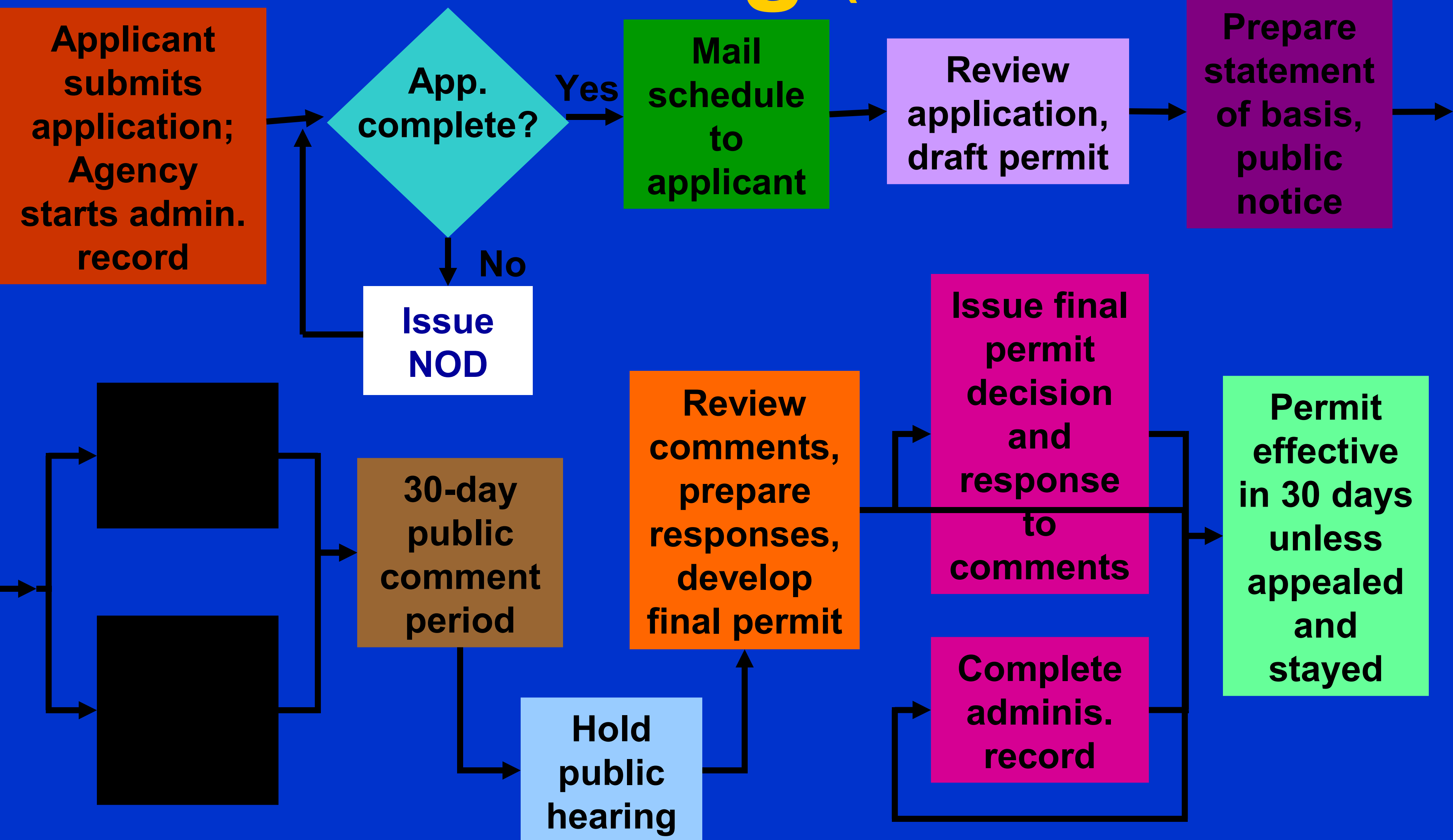
Administrative Record

- Final approved financial assurance mechanism
- Documentation illustrating how review determined submission meets requirements

Lesson 20

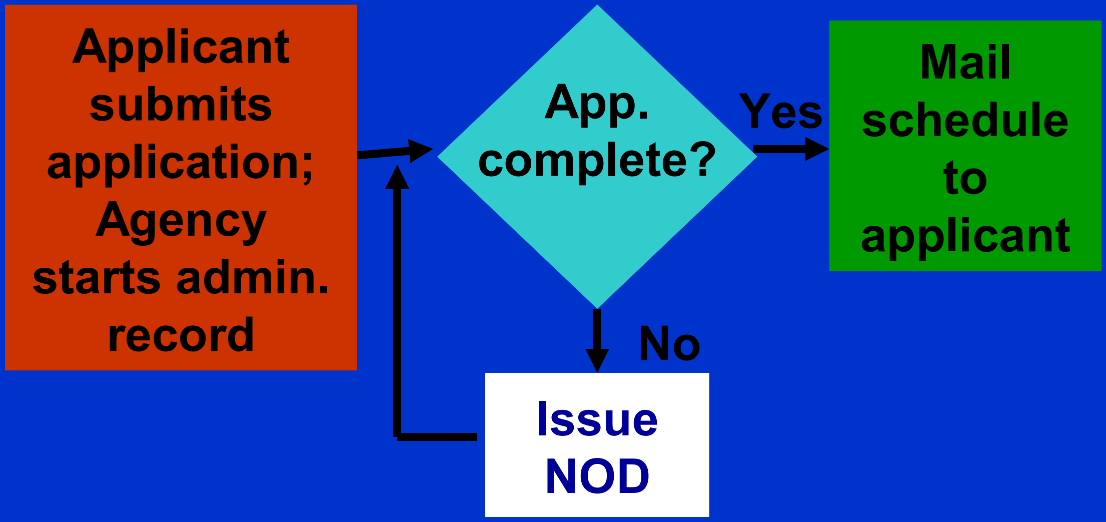
Public Participation in the Permitting Process

Public Participation in UIC Permitting (40 CFR Part 124)

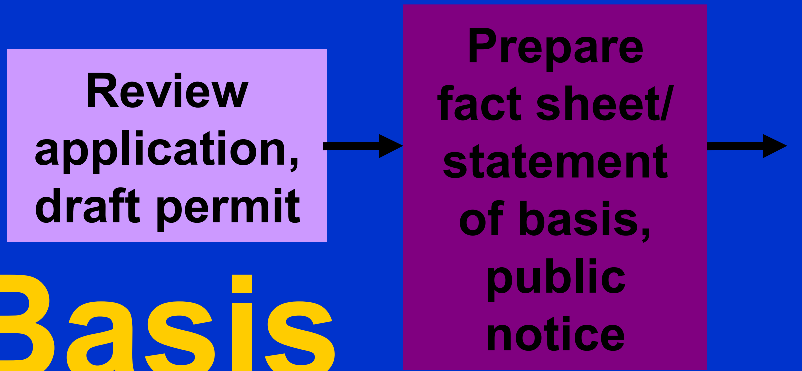


Administrative Record

- The record for the decision made on a UIC permit application must be kept and made available to the public
- Includes **all** documents associated with decision making process
  - Draft permit
  - Statement of basis
  - NODs
  - Comment letters and responses
  - Other correspondence



Fact Sheet or Statement of Basis



- A fact sheet must be prepared for:
  - Every draft permit for a major UIC facility
  - Every draft permit the Director finds is the subject of "wide-spread public interest or raises major issues"
- Statement of basis prepared for other UIC facilities *in lieu of* fact sheet

Draft Permit Issuance

- Draft permits must be announced through a public notice
- Opportunity for a public hearing must be provided
- A final permit decision must be accompanied by a response to any comments submitted on the draft permit

Public Notice

- Public notice prepared and published. Must allow at least 30 days for public comment once draft decision has been made on the permit application
- Describes draft action, where draft can be reviewed, invites comment
- The notice may include details of a public hearing, if one has been scheduled

Hold public hearing

Public Hearing

- Opportunity to provide written or verbal testimony on the draft action
- May be scheduled in advance or requested during the public comment period
- The Director must hold a hearing if there is “a significant degree of public interest” in the draft permit

Review comments, prepare responses, develop final permit → Issue final permit decision and response to comments → Complete adminis. record →

Response to Comments

- The comment period may be extended or reopened
- The agency responds to all public comments received during the public comment period when it issues a final permit decision
- The response to comments is part of the administrative record and must be made available to the public

Permit Appeals

Permit effective in 30 days unless appealed and stayed

- The public may appeal the final action within 30 days
- Appeals may be filed by the permit applicant or any interested person - as long as they commented during the public comment period or participated in the public hearing

Unpleasant Surprises

- Other issues that can arise
  - Highly political sites
  - New information at the last minute
  - Public claiming lack of information
- Anticipating issues and planning well can alleviate many of the problems and headaches!

Lesson 21
Summary and Conclusions

Additional Conditions

- Additional conditions may be established on a case-by-case basis
  - To prevent migration of fluids into USDWs
  - To assure compliance with all applicable requirements of SDWA and the UIC regulations

Hearing versus Doing

- Course content is focused on the key elements of permitting
- Site-specific conditions may introduce additional issues not addressed in detail in this course

Conclusions

- Consult other technical resources (see appendices to this training manual)
- Ask questions of the owner/operator
- Use a team approach to deal with areas that are new to you